BP PLC
Form 20-F/A
July 05, 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
[ü]	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2005**
	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	**New York Stock Exchange*** **Chicago Stock Exchange*** **NYSE Arca***
	*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	**20,657,044,719**
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 [ü] 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 [ü]

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 [ü] 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 [ü] Accelerated filer [ ] Non-accelerated filer [ ]

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

Item 17 [ ] Item 18 [ü]

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 [ü]

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EXPLANATORY NOTE

This Amendment No. 1 (Amendment No. 1) to the Annual Report on Form 20-F for the year ended December 31, 2005, as filed with the U.S. Securities and Exchange Commission (the SEC) on June 30, 2006 (the Original Form 20-F), is being filed solely to correct certain non-substantive formatting errors which arose in the process of converting the Original Form 20-F to electronic form suitable for filing on the SEC s EDGAR system. Except as described above, no other changes have been made to the Original Form 20-F.

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CERTAIN DEFINITIONS

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

Oil and natural gas reserves

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

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

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

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

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

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

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

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

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

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

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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.

Associate 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.

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.

Dollar or $ The US dollar.

EU European Union

Gas Natural Gas.

Hydrocarbons Crude oil and natural gas.

IFRS International Financial Reporting Standards as adopted by the EU.

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

Liquids Crude oil, condensate and natural gas liquids.

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.

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 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.

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.

For all periods up to and including the year ended December 31, 2004, BP prepared its financial statements in accordance with UK generally accepted accounting practice (UK GAAP). BP, together with all other European Union (EU) companies listed on an EU stock exchange, was required to prepare consolidated financial statements in accordance with International Financial Reporting Standards as adopted by the EU with effect from January 1, 2005. The Annual Report and Accounts for the year ended December 31, 2005 are BP s first consolidated financial statements prepared under IFRS. In preparing these financial statements, the Group has complied with all International Financial Reporting Standards applicable for periods beginning on or after January 1, 2005. In addition, BP has also decided to adopt early IFRS 6 Exploration for and Evaluation of Mineral Resources , the amendment to IAS 19 Amendment to International Accounting Standard IAS 19 Employee Benefits: Actuarial Gains and Losses, Group Plans and Disclosures , the amendment to IAS 39 Amendment to International Accounting Standard IAS 39 Financial Instruments: Recognition and Measurement: Cash Flow Hedge Accounting of Forecast Intragroup Transactions and IFRIC 4 Determining whether an Arrangement contains a Lease . The EU has adopted all standards and interpretations adopted by BP for its 2005 reporting.

The financial information for 2004 and 2003 has been restated to reflect the following, all with effect from January 1, 2005: (a) the adoption by the Group of IFRS (see Item 18 Financial Statements Note 3 on page F-30 and Note 52 on page F-145); (b) the transfer of the Mardi Gras pipeline system from Exploration and Production to Refining and Marketing; (c) the transfer of the aromatics and acetyls operations and the petrochemicals assets that are integrated with our Gelsenkirchen refinery in Germany from the former Petrochemicals segment to Refining and Marketing; (d) the transfer of the olefins and derivatives operations from the former Petrochemicals segment to the Olefins and Derivatives business (the legacy historical results of other petrochemicals assets that had been divested during 2004 and 2003 are included within Other businesses and corporate); (e) the transfer of the Grangemouth and Lavera refineries from Refining and Marketing to the Olefins and Derivatives business; and (f) the transfer of the Hobbs fractionator from Gas, Power and Renewables to the Olefins and Derivatives business. The Olefins and Derivatives business is reported within Other businesses and corporate. This reorganization was a precursor to seeking to divest the Olefins and Derivatives business. As indicated in Item 18 Financial Statements Note 5 on page F-35, we divested Innovene on December 16, 2005. Innovene represented the majority of the Olefins and Derivatives business. Innovene operations have been treated as discontinued operations in accordance with IFRS 5 Non-current Assets Held for Sale and Discontinued Operations . Item 18 Financial Statements Note 5 on page F-35 provides further detail. Under US GAAP, Innovene operations would not be classified as discontinued operations due to BP s continuing customer/ supplier arrangements with Innovene.

In the circumstances of discontinued operations, IFRS require that the profits earned by the discontinued operations, in this case the Innovene operations, on sales to the continuing operations be eliminated on consolidation from the discontinued operations, and attributed to the continuing operations and vice versa. This adjustment has two offsetting elements: the net margin on crude refined by Innovene as substantially all crude for their refineries is supplied by BP and most of the refined products manufactured are taken by BP; and the margin on sales of feedstock from BP s US refineries to Innovene manufacturing plants. The profits attributable to individual segments are not affected by this adjustment. Neither does this representation indicate the profits earned by continuing or Innovene operations, as if they were stand-alone entities, for past periods or likely to be earned in future periods.

	Year ended December 31,		
	2005	**2004**	**2003**
	($ million except per share amounts)		
IFRS			
Income statement data			
Sales and other operating revenues from continuing operations (a)	239,792	192,024	164,653
Profit before interest and taxation for continuing operations (a)	32,182	25,746	18,776
Profit from continuing operations (a)	22,133	17,884	12,681
Profit for the year	22,317	17,262	12,618
Profit for the year attributable to BP shareholders	22,026	17,075	12,448
Per ordinary share: (cents)			
Profit for the year attributable to BP shareholders:			
Basic	104.25	78.24	56.14
Diluted	103.05	76.87	55.61
Profit from continuing operations attributable to BP shareholders:			
Basic	103.38	81.09	56.42
Diluted	102.19	79.66	55.89
Dividends per share (cents)	34.85	27.70	25.50
Dividends per share (pence)	19.152	15.251	15.658
Ordinary Share data (b)			
Average number outstanding of 25 cents ordinary shares (shares million undiluted)	21,126	21,821	22,171
Average number outstanding of 25 cents ordinary shares (shares million diluted)	21,411	22,293	22,424
Balance sheet data			
Total assets	206,914	194,630	172,491
Net assets	80,450	78,235	70,264
Share capital	5,185	5,403	5,552
BP shareholders equity	79,661	76,892	69,139
Finance debt due after more than one year	10,230	12,907	12,869
Debt to borrowed and invested capital (c)	11%	14%	15%

Selected historical financial data is based on financial statements prepared in accordance with IFRS and accordingly is shown for the three years subsequent to the date of transition to IFRS.

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	Year ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
	($ million except per share amounts)				
US GAAP					
Income statement data					
Revenues	252,168	203,303	173,615	145,991	145,902
Profit for the year attributable to BP shareholders (d)	19,642	17,090	12,941	8,109	4,467
Comprehensive income	17,053	17,371	19,689	10,256	2,952
Profit per ordinary share: (cents)					
Basic	92.96	78.31	58.36	36.20	19.90
Diluted	91.91	76.88	57.79	36.02	19.78
Profit per American Depositary Share: (cents)					
Basic	557.76	469.86	350.16	217.20	119.40
Diluted	551.46	461.28	346.74	216.12	118.68
Balance sheet data					
Total assets	213,722	206,139	186,576	164,103	145,990
Net assets	85,936	86,435	80,292	67,274	62,786
BP shareholders equity	85,147	85,092	79,167	66,636	62,188

(a) Excludes Innovene which was treated as a discontinued operation in accordance with IFRS 5 Non-current Assets Held for Sale and Discontinued Operations . See Item 18 Financial Statements Note 5 on page F-35. Under US GAAP, Innovene is not treated as a discontinued operation.

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

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

(d) Under US GAAP, Innovene is not treated as a discontinued operation. See Item 18 Financial Statements Note 55 on page F-191. As such, the results of Innovene are included within the profit for the year, as adjusted to accord with US GAAP.

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.

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The following table shows dividends announced and paid 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 158. 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 is no refund available to shareholders resident in the US. Refer to Item 10 Additional Information Taxation for more information.

		March	June	September	December	Total
Dividends per American Depositary Share						
2001	UK pence	21.7	22.0	23.5	22.8	90.0
	US cents	31.5	31.5	33.0	33.0	129.0
	Can. cents	47.9	48.3	50.4	52.6	199.2
2002	UK pence	24.3	24.3	23.3	23.4	95.3
	US cents	34.5	34.5	36.0	36.0	141.0
	Can. cents	54.9	54.1	56.7	56.1	221.8
2003	UK pence	22.9	23.7	24.2	23.1	93.9
	US cents	37.5	37.5	39.0	39.0	153.0
	Can. cents	57.4	54.3	54.0	51.1	216.8
2004	UK pence	22.0	22.8	23.2	23.5	91.5
	US cents	40.5	40.5	42.6	42.6	166.2
	Can. cents	53.7	54.8	56.7	52.2	217.4
2005	UK pence	27.1	26.7	30.7	30.4	114.9
	US cents	51.0	51.0	53.55	53.55	209.1
	Can. cents	64.0	63.2	65.3	63.7	256.2

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 79.

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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.

Delivery Risks

Delivery risks are those specific to implementing activities contained in our Group plan. Successful execution of this plan depends critically on implementing the set of activities described. Hence, our delivery risks are those factors that would result in our failure to deliver these activities economically. The most significant risks include:

Upstream renewal: Inability to renew the portfolio and sustain long-term reserves replacement. The challenge is growing due to increasing competition for access to opportunities globally.

Major project delivery: Poor delivery of any major project that underpins production growth and/or a major programme designed to enhance shareholder value.

Portfolio repositioning: Inability to complete planned disposals and/or lack of material positions in new markets (and hence the inability to capture above-average market growth).

Inherent 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, gas and product 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 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 that could have a significant effect on the Group s results of operations in the period in which it occurs.

Regulatory Risk: 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 that 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. Fluctuations in exchange rates can therefore give rise to foreign exchange exposures, with a consequent impact on underlying costs.

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.

Enduring 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 minimal 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.

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

Drilling and Production Risk: Exploration and production require high levels of investment and have particular economic risks and opportunities and may often involve innovative technologies. 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.

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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 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, future production volumes, 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.

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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 sales and other operating revenues include sales between BP businesses.

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

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

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

Our agent in the USA is:

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

Overview of the Group

Our three operating business segments are Exploration and Production; Refining and Marketing; and Gas, Power and Renewables. Exploration and Production s activities include oil and natural gas exploration, development and production (upstream activities), together with related pipeline transportation and processing activities (midstream activities). The activities of Refining and Marketing include oil supply and trading and the manufacture and marketing of petroleum products, including aromatics and acetyls as well as refining and marketing. Gas, Power and Renewables activities include the marketing and trading of natural gas, natural gas liquids (NGLs), liquefied natural gas (LNG), LNG shipping and regasification activities, and low-carbon power development, including solar and wholesale marketing and trading (BP Alternative Energy). The Group provides high quality technological support for all its businesses through its research and engineering activities.

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, Russia, South America, Australasia, Asia and parts of Africa. Currently, around 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 25% located in the UK and the Rest of Europe.

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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 and the 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, BP has both a retail and refining presence, strengthened by the acquisition of Veba Oil (Veba) in 2002, which markets gasoline under the Aral brand. Our Aromatics and Acetyls business maintains a manufacturing position globally with emphasis on growth in Asia. We also have, or are growing, businesses elsewhere in the world under the BP brand.

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. We are investing to offer real alternatives for generation of power with low-carbon emissions. We have plans to invest in a new business called BP Alternative Energy, which aims to extend significantly our capability in solar, wind power, hydrogen power and gas-fired generation.

Acquisitions and Disposals

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

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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. In December 2005, TNK-BP disposed of non-core producing assets in the Saratov region, along with the Orsk refinery and certain TNK-BP operated petrol stations. The disposals allow TNK-BP to streamline its operations and concentrate on strategic investments in projects with high-growth potential.

Disposal proceeds in 2003 amounted to $6,356 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 in 2002.

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. These two entities were subsequently included as part of the sale of Innovene to INEOS (see below).

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 $4,961 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 specialty intermediate chemicals and Fabrics and Fibres businesses and the sale of two natural gas liquids plants.

In 2005, there were no significant acquisitions. Disposal proceeds were $11,200 million, which includes net cash proceeds from the sale of Innovene to INEOS of $8,304 million after selling costs, closing adjustments and liabilities. Innovene represented the majority of the Olefins and Derivatives business. Additionally, it includes proceeds from the sale of the Group s interest in the Ormen Lange field in Norway.

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Resegmentation in 2006

With effect from January 1, 2006 the following changes to the business segments have been implemented:

Following the sale of Innovene to INEOS in December 2005, the transfer of three equity-accounted entities (Shanghai SECCO Petrochemical Company Limited in China and Polyethylene Malaysia Sdn Bhd and Ethylene Malaysia Sdn Bhd, both in Malaysia), previously reported in Other businesses and corporate, to Refining and Marketing.

The formation of BP Alternative Energy in November 2005 has resulted in the transfer of certain mid-stream assets and activities to Gas, Power and Renewables:

South Houston Green Power co-generation facility (in Texas City refinery) from Refining and Marketing.

Watson Cogeneration (in Carson City refinery) from Refining and Marketing.

Phu My Phase 3 combined cycle gas turbine (CCGT) plant in Vietnam from Exploration and Production.

The transfer of Hydrogen for Transport activities from Gas, Power and Renewables to Refining and Marketing.

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Financial and Operating Information

The following table summarizes the Group s sales and other operating revenues of continuing operations, profit and capital expenditure for the last three years and total assets at the end of each of those years. The financial information for 2004 and 2003 has been restated to reflect: (a) the adoption by the Group of IFRS; (b) various reorganizations as a precursor to seeking to divest the Olefins and Derivatives business; and (c) the presentation of Innovene as a discontinued operation as a result of its divestment. See Item 3 Selected Financial Information page 6 for further details related to these restatements.

	Year ended December 31,		
	2005	**2004**	**2003**
Sales and other operating revenues of continuing operations	239,792	192,024	164,653
Profit for the year	22,317	17,262	12,618
Profit for the year attributable to BP shareholders	22,026	17,075	12,448
Capital expenditure and acquisitions (a)	14,149	16,651	19,623
Total assets	206,914	194,630	172,491

(a) There were no significant acquisitions in 2005. 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; and for 2003 includes $5,794 million for the acquisition of our interest in TNK-BP.

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 14) 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 2005, 2004 and 2003 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 7 on page F-39.

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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.

	Year ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Crude oil production for subsidiaries (thousand barrels per day)	1,423	1,480	1,615	1,766	1,723
Crude oil production for equity-accounted entities (thousand barrels per day)	1,139	1,051	506	252	208
Natural gas production for subsidiaries (million cubic feet per day)	7,512	7,624	8,092	8,324	8,287
Natural gas production for equity-accounted entities (million cubic feet per day)	912	879	521	383	345
Estimated net proved crude oil reserves for subsidiaries (million barrels) (a)(b)	6,360	6,755	7,214	7,762	7,217
Estimated net proved crude oil reserves for equity-accounted entities (million barrels) (a)(c)	3,205	3,179	2,867	1,403	1,159
Estimated net proved natural gas reserves for subsidiaries (billion cubic feet) (a)(d)	44,448	45,650	45,155	45,844	42,959
Estimated net proved natural gas reserves for equity-accounted entities (billion cubic feet) (a)(e)	3,856	2,857	2,869	2,945	3,216

(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 29 million barrels (40 million barrels at December 31, 2004 and 55 million barrels at December 31, 2003) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

(c) Includes 95 million barrels in respect of the 4.47% minority interest in TNK-BP at December 31, 2005 and includes 127 million barrels and 97 million barrels in respect of the 5.9% minority interest in TNK-BP at December 31, 2004 and December 31, 2003, respectively.

(d) Includes 3,812 billion cubic feet of natural gas (4,064 billion cubic feet at December 31, 2004 and 4,505 billion cubic feet at December 31, 2003) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

(e) Includes 57 billion cubic feet in respect of the 4.47% minority interest in TNK-BP at December 31, 2005 and includes 13 billion cubic feet (December 31, 2003 nil) in respect of the 5.9% minority interest in TNK-BP at December 31,2004.

During 2005, 681 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 996 mmboe, BP s proved reserves for subsidiaries, were 14,023 mmboe at December 31, 2005. These proved reserves are mainly located in the USA (43%), Rest of Americas (21%), Asia Pacific (10%) and the UK (9%).

For equity-accounted entities, 721 mmboe were added to proved reserves, (excluding purchases and sales), production was 478 mmboe and proved reserves were 3,870 mmboe at December 31, 2005.

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

SEGMENTAL INFORMATION

The following tables show sales and other operating revenues and profit before finance costs, other finance expense and tax by business and by geographical area, for the years ended December 31, 2005, 2004 and 2003.

Year ended December 31, 2005

By business	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total Group	Innovene operations	Consolidation adjustment and eliminations (a)	Total continuing operations
					($ million)				
Sales and other operating revenues									
Segment revenues	47,210	213,465	25,557	21,295	(55,359)	252,168	(20,627)	8,251	239,792
Less: sales between businesses	(32,606)	(11,407)	(3,095)	(8,251)	55,359		8,251	(8,251)	
Third party sales	14,604	202,058	22,462	13,044		252,168	(12,376)		239,792
Results									
Profit (loss) before interest and tax	25,508	6,442	1,104	(523)	(208)	32,323	(668)	527	32,182
Includes									
Equity-accounted income	3,238	238	19	34		3,529	14		3,543

Year ended December 31, 2004

By business	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total Group	Innovene operations	Consolidation adjustment and eliminations (a)	Total continuing operations
					($ million)				
Sales and other operating revenues									
Segment revenues	34,700	170,749	23,859	17,994	(43,999)	203,303	(17,448)	6,169	192,024
Less: sales between businesses	(24,756)	(10,632)	(2,442)	(6,169)	43,999		6,169	(6,169)	
Third party sales	9,944	160,117	21,417	11,825		203,303	(11,279)		192,024

Results									
Profit (loss) before interest and tax	18,087	6,544	954	(362)	(191)	25,032	526	188	25,746
Includes									
Equity-accounted income	1,985	259	6	18		2,268	12		2,280

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By business	Year ended December 31, 2003								
	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total Group	Innovene operations	Consolidation adjustment and eliminations (a)	Total continuing operations
	($ million)								
Sales and other operating revenues									
Segment revenues	30,621	143,441	22,568	13,978	(36,993)	173,615	(13,463)	4,501	164,653
Less: sales between businesses	(22,885)	(7,644)	(1,963)	(4,501)	36,993		4,501	(4,501)	
Third party sales	7,736	135,797	20,605	9,477		173,615	(8,962)		164,653
Results									
Profit (loss) before interest and tax	15,084	3,235	578	(108)	(61)	18,728	(145)	193	18,776
Includes									
Equity-accounted income	949	241	(5)	14		1,199	15		1,214

(a) In the circumstances of discontinued operations, International Accounting Standards require that the profits earned by the discontinued operations, in this case the Innovene operations, on sales to the continuing operations be eliminated on consolidation from the discontinued operations and attributed to the continuing operations and vice versa. This adjustment has two offsetting elements: the net margin on crude refined by Innovene as substantially all crude for its refineries is supplied by BP and most of the refined products manufactured are taken by BP; and the margin on sales of feedstock from BP s US refineries to Innovene s manufacturing plants. The profits attributable to individual segments are not affected by this adjustment. Neither does this representation indicate the profits earned by continuing or Innovene operations, as if they were standalone entities, for past periods or likely to be earned in future periods.

By geographical area	Year ended December 31, 2005				
	UK	Rest of Europe	USA	Rest of World	Total
	($ million)				
Sales and other operating revenues					
Segment revenues	95,375	72,972	101,190	60,314	329,851
Less: sales attributable to Innovene operations	(2,610)	(8,667)	(4,309)	(686)	(16,272)

Segment revenues from continuing operations	92,765	64,305	96,881	59,628	313,579
Less: sales between areas	(38,081)	(5,013)	(2,362)	(16,541)	(61,997)
Less: sales by continuing operations to Innovene	(5,599)	(4,640)	(1,508)	(43)	(11,790)
Third party sales of continuing operations	49,085	54,652	93,011	43,044	239,792
Results					
Profit (loss) before interest and tax from continuing operations	1,167	5,206	12,639	13,170	32,182
Includes					
Equity-accounted income	(8)	18	86	3,447	3,543

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By geographical area	UK	Rest of Europe	USA	Rest of World	Total
	Year ended December 31, 2004				
	($ million)				
Sales and other operating revenues					
Segment revenues	59,615	52,540	86,358	48,534	247,047
Less: sales attributable to Innovene operations	(2,365)	(7,682)	(4,109)	(672)	(14,828)
Segment revenues from continuing operations	57,250	44,858	82,249	47,862	232,219
Less: sales between areas	(18,846)	(1,396)	(1,539)	(10,188)	(31,969)
Less: sales by continuing operations to Innovene	(5,263)	(896)	(2,064)	(3)	(8,226)
Third party sales of continuing operations	33,141	42,566	78,646	37,671	192,024
Results					
Profit (loss) before interest and tax from continuing operations	2,875	3,121	9,725	10,025	25,746
Includes					
Equity-accounted income	9	17	92	2,162	2,280

By geographical area	UK	Rest of Europe	USA	Rest of World	Total
	Year ended December 31, 2003				
	($ million)				
Sales and other operating revenues					
Segment revenues	36,253	48,138	79,092	38,316	201,799
Less: sales attributable to Innovene operations	(1,879)	(6,105)	(3,265)	(534)	(11,783)
Segment revenues from continuing operations	34,374	42,033	75,827	37,782	190,016
Less: sales between areas	(6,953)	(3,160)	(714)	(8,258)	(19,085)
Less: sales by continuing operations to Innovene	(3,947)	(876)	(1,455)		(6,278)
Third party sales of continuing operations	23,474	37,997	73,658	29,524	164,653
Results					
Profit (loss) before interest and tax from continuing operations	3,348	1,819	7,008	6,601	18,776
Includes					
Equity-accounted income	11	39	99	1,065	1,214

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EXPLORATION AND PRODUCTION

Our Exploration and Production business includes upstream and midstream activities in 26 countries, including the USA, UK, Angola, Azerbaijan, Canada, Egypt, Russia, Trinidad, and locations within Asia Pacific, South America and the Middle East. Upstream activities involve oil and natural gas exploration and field development and production. Our exploration programme is currently focused around the Deepwater Gulf of Mexico, Angola, Trinidad, Egypt, Algeria and Russia. Major development areas include the Deepwater Gulf of Mexico, Azerbaijan, Algeria, Angola, Egypt and Asia Pacific. During 2005, production came from 22 countries.

Midstream activities involve the management of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities. Our most significant midstream pipeline interests include: the Trans Alaska Pipeline System; the Forties Pipeline System and the Central Area Transmission System pipeline both in the UK sector of the North Sea; and the Baku-Tbilisi-Ceyhan pipeline running through Azerbaijan, Georgia and Turkey. Our significant LNG interests include: the Atlantic LNG plant in Trinidad; our interests in the Sanga-Sanga Production Sharing Agreement (PSA) which supplies natural gas to the Bontang LNG plant, and the Tangguh PSA, which is under construction, both in Indonesia; and through our share of LNG from the North West Shelf natural gas development in Australia.

With effect from January 1, 2005, we transferred the Mardi Gras pipeline system in the Gulf of Mexico to the Refining and Marketing segment. The 2004 and 2003 data below has been restated to reflect this transfer.

	Year ended December 31,		
	2005	**2004**	**2003**
		($ million)	
Sales and other operating revenues from continuing operations (a)	47,210	34,700	30,621
Profit before interest and tax from continuing operations	25,508	18,087	15,084
Total assets	93,479	85,808	79,446
Capital expenditure and acquisitions	10,237	11,008	15,192
		($ per barrel)	
Average BP crude oil realizations (b)	50.27	36.45	28.23
Average BP NGL realizations (b)	33.23	26.75	19.26
Average BP liquids realizations (b)(c)	48.51	35.39	27.25
Average West Texas Intermediate oil price	56.58	41.49	31.06
Average Brent oil price	54.48	38.27	28.83
		($ per thousand cubic feet)	
Average BP natural gas realizations (b)	4.90	3.86	3.39
Average BP US natural gas realizations (b)	6.78	5.11	4.47
		($ per mmbtu)	
Average Henry Hub gas price (d)	8.65	6.13	5.37

(a) Includes profit after interest and tax of equity-accounted entities.

(b) The Exploration and Production business does not undertake any hedging activity. Consequently, realizations reflect the market price achieved. Realizations are based on sales of consolidated subsidiaries only this excludes equity-accounted entities.

(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 and Venezuela), Middle East (including Abu Dhabi, Sharjah and Pakistan), North America Gas (Onshore USA and Canada) and the

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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, and the Deepwater Gulf of Mexico; and Russia.

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

The Exploration and Production strategy is to build production with improving returns by:

- Focusing on finding the largest fields, concentrating our involvement in a limited number of the world s most prolific hydrocarbon basins;
- Building leadership positions in these areas; and
- Managing the decline of existing producing assets and divesting assets when they no longer compete in our portfolio.

This strategy is underpinned by a focused exploration strategy in areas with the potential for large oil and natural gas fields as new profit centres. Through the application of advanced technology and significant investment, we have gained a strong position in many of these areas. Within our existing profit centres, we seek to manage the decline through the application of technology, reservoir management, maintaining operating efficiency and investing in new projects. We also continually review our existing assets and dispose of them when the opportunities for future investment are no longer competitive compared with other opportunities within our portfolio and offer greater value to another operator.

In support of growth, 2005 capital expenditure including acquisitions was $10.2 billion (2004 $11.0 billion and 2003 $15.2 billion). Acquisitions in 2004 and 2003 comprised essentially our progressive investment in TNK-BP of $1.4 billion and $5.8 billion, respectively. Excluding acquisitions, capital expenditure in 2005 amounted to $10.1 billion (2004, $9.6 billion and 2003 $9.4 billion) and is planned to be around $11 billion in 2006. The projected increase in capital expenditure in 2006 reflects our project programme, managed within the context of our disciplined approach to capital investment, and taking into account sector specific inflation.

Development expenditure incurred in 2005, excluding midstream activities, was $7,678 million compared with $7,270 million in 2004 and $7,537 million in 2003. This reflects the investment we have been making in our new profit centres and the development phase on many of our major projects.

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 2005 were $1,266 million compared to $1,039 million in 2004 and $824 million in 2003. These costs include exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred. About 28% of 2005 exploration and appraisal costs were directed towards appraisal activity. In 2005, we participated in 98 gross (44 net) exploration and appraisal wells in 14 countries. The principal areas of activity were Angola, Egypt, Russia (outside TNK-BP), Trinidad, Turkey and the USA.

Total exploration expense in 2005 of $684 million (2004 $637 million and 2003 $542 million) includes the write-off of unsuccessful drilling activity in the Deepwater Gulf of Mexico ($120 million), in Onshore North America ($18 million), in Egypt ($13 million) and others ($21 million).

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In 2005, we obtained upstream rights in several new tracts, which include the following:

In Algeria, we were awarded three new blocks (BP 100%), two in the Illizi Basin and one in the Benoud Basin.

In Egypt, we were awarded two new blocks in the shallow water Nile Delta, Burullus (BP 100%) and North El Burg (BP 50%).

In the Gulf of Mexico, we were awarded 41 blocks (BP 100%) in the Deepwater and 8 blocks (BP 100%) in the Shelf through the Outer Continental Shelf Lease Sales 194 and 196.

In 2005, we were involved in discoveries, the most significant of which were in Angola, Russia, Trinidad and the USA. In most cases, reserve bookings from these fields will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling. Our 2005 discoveries included the following:

In Angola, we made further discoveries in the ultra deep water (greater than 1,500 metres) in Block 31 (BP 26.7% and operator) with Ceres, Juno, Astraea and Hebe wells. In 2006, the Urano discovery was announced in the same block.

In Trinidad, BP Trinidad and Tobago LLC (BP 70%) made a discovery with the Coconut Deep well.

In Russia, a second discovery was made in the Kaigansky-Vasukansky licence in the south of the Sakhalin V area with the Udachnaya well (BP 49%)

In the Deepwater Gulf of Mexico, we continued our successful exploration efforts with a number of new discoveries.

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 resources move through various non-proved resource sub-categories as their technical and commercial maturity increases through appraisal activity.

Resources in a field will only be categorized as proved reserves 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 that forms part of a holistic and integrated system of internal control. BP s process to manage reserve bookings has been centrally controlled for over 15 years and it currently has several key elements.

The first 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

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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.

For the executive directors and senior management, no specific portion of compensation bonuses is directly related to oil and gas reserves targets. Additions to proved reserves is one of several indicators by which the performance of the Exploration and Production business segment is assessed by the Remuneration Committee for the purposes of determining compensation bonuses for the executive directors and senior management. Other indicators include a number of financial and operational measures.

BP s variable pay programme for the other senior managers in the Exploration and Production business segment is based on Individual Performance Contracts. Individual Performance Contracts are 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, 2005, 2004, and 2003 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 (jointly controlled entities and associates) 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 21% 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 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. Fifteen 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.

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The Company s proved reserves estimates for the year ended December 31, 2005 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 2005 year-end marker prices used were Brent $58.21/bbl (2004 $40.24/bbl and 2003 $30.10/bbl) and Henry Hub $9.52/mmbtu (2004 $6.01/mmbtu and 2003 $5.76/mmbtu). The other 2005 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 14,023 mmboe at December 31, 2005, a decrease of 4.1% compared with December 31, 2004. Natural gas represents about 55% of these reserves. This reduction includes net sales of 287 mmboe largely comprising a number of assets in Norway and Trinidad. The proved reserve replacement ratio was 68% (2004 78% and 2003 119%). 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 40% (2004 64% and 2003 39%). 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 2005, total additions to the Group s proved reserves (excluding sales and purchases of reserves-in-place and equity-accounted entities) amounted to 681 mmboe, mostly through extensions to and improved recovery from existing fields and discoveries of new fields. Of these reserve additions, approximately 77% 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 (Kizomba C), United States (Wamsutter, Ursa, Shenzi) and Trinidad (Coconut) and it is planned to bring these into production over the period 2006 2011.

Total hydrocarbon proved reserves, on an oil equivalent basis for equity-accounted entities alone, comprised 3,870 mmboe at December 31, 2005, an increase of 5.4% compared with December 31, 2004. Natural gas represents about 17% of these reserves. The proved reserve replacement ratio for equity-accounted entities alone was 151% (2004 114% and 2003 72%), and the proved reserve replacement ratio for equity-accounted entities alone but including sales and purchases of reserves-in-place was 141% (2004 170% and 2003 796%).

Additions to proved developed reserves in 2005 for subsidiaries were 632 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 63% (2004 70% and 2003 -2%).

Additions to proved developed reserves in 2005 for equity-accounted entities were 474 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 99% (2004 180% and 2003 642%).

Our total hydrocarbon production during 2005 averaged 2,718 thousand barrels of oil equivalent per day (mboe/d), for subsidiaries and 1,296 mboe/d, for equity-accounted entities, a decrease of 2.8% and an increase of 7.8%, respectively, compared with 2004. For subsidiaries, 39% of our production was in the USA, 17% in the UK. For equity-accounted entities, 77% of production is from TNK-BP.

Total production for 2006 is estimated at an average of between 2.8 and 2.85 mmboe/d for subsidiaries and between 1.3 and 1.35 mmboe/d for equity-accounted entities; these estimates are based on the Group s asset portfolio at January 1, 2006, anticipated start-ups in 2006 and Brent at $40/bbl, before any 2006 disposal effects, and before any effects of prices above $40/bbl on volumes in Production Sharing Agreements. The daily production of the Gulf of Mexico Shelf assets, whose sale was announced in April 2006, is estimated at 27 mboe.

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 growth in our equity-accounted joint venture, TNK-BP, is expected to moderate to between 2% and 3% over the period 2005 to 2010.

The most important determinants of cash flows in relation to our oil and natural gas production are the prices of these commodities. At constant prices, 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. See Item 5 Liquidity and Capital Resources on page 93.

The following tables show BP s estimated net proved reserves as at December 31, 2005.

Estimated net proved reserves of liquids at December 31, 2005 (a) (b)

	Developed	Undeveloped	Total
		(million barrels)	
UK	496	184	680
Rest of Europe	225	86	311
USA	1,984	1,429	3,413
Rest of Americas	215	286	501(c)
Asia Pacific	70	95	165
Africa	142	536	678
Russia			
Other	69	543	612
	3,201	3,159	6,360
Equity-accounted entities			3,205(d)

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Estimated net proved reserves of natural gas at December 31, 2005 (a) (b)

	Developed	Undeveloped	Total
		(billion cubic feet)	
UK	2,382	904	3,286
Rest of Europe	245	80	325
USA	11,184	4,198	15,382
Rest of Americas	3,560	10,504	14,064 (e)
Asia Pacific	1,459	5,375	6,834
Africa	934	2,000	2,934
Russia			
Other	281	1,342	1,623
	20,045	24,403	44,448
Equity-accounted entities			3,856 (f)
Net proved reserves on an oil equivalent basis (mmboe)			
Group			14,023
Equity-accounted entities			3,870

(a) Net proved reserves of crude oil and natural gas, stated as of December 31, 2005, 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 associates 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. As at the end of 2005, BP had proved reserves in 21 fields in the Deepwater Gulf of Mexico that had been initially booked prior to production flow testing. Of these fields, 18 have been in production and two, Thunder Horse and Atlantis, are expected to begin production in the second half of the year and around the end of 2006, respectively. A further field is in the early stages of development.

(c) Includes 29 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

(d) Includes 95 million barrels of crude oil in respect of the 4.47% minority interest in TNK-BP.

(e) Includes 3,812 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

(f) Includes 57 billion cubic feet of natural gas in respect of the 4.47% minority interest in TNK-BP.

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The following tables show BP s production by major field for 2005, 2004 and 2003.

Liquids

			Year ended December 31,		
			Net production		
Production	**Field or Area**	**Interest**	**2005**	**2004**	**2003**
		(%)	(thousand barrels per day)		
Alaska	Prudhoe Bay*	26.4	89	97	105
	Kuparuk	39.2	62	68	73
	Northstar*	98.6	46	49	46
	Milne Point*	100.0	37	44	44
	Other	Various	34	37	43
Total Alaska			268	295	311
Lower 48 onshore (a)	Various	Various	130	142	160
Gulf of Mexico Deepwater (a)	Na Kika*	50.0	44	27	
	Horn Mountain*	66.6	26	41	42
	King*	100.0	24	26	31
	Mars	28.5	21	35	43
	Ursa	22.7	19	29	17
	Other	Various	64	47	73
Gulf of Mexico Shelf (a)	Other	Various	16	24	49
Total Gulf of Mexico			214	229	255
Total USA			612	666	726
UK offshore (a)	ETAP	Various	49	55	56
	Foinaven*	Various	39	48	55
	Magnus*	85.0	30	34	39
	Schiehallion/Loyal*	Various	28	39	42
	Harding*	70.0	22	27	34
	Andrew*	62.8	12	12	17
	Other	Various	75	89	105
Total UK offshore			255	304	348
Onshore	Wytch Farm*	67.8	22	26	29
Total UK			277	330	377
Netherlands	Various	Various	1	1	1
Norway (a)	Valhall*	28.1	25	25	21
	Draugen	18.4	20	27	25

	Ula*	80.0	17	16	16
	Other	Various	12	8	21
Total Rest of Europe			75	77	84

* BP operated.

Out of nine fields, BP operates six and Shell three.

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Production	Field or Area	Interest	Year ended December 31, Net production 2005	2004	2003
		(%)	(thousand barrels per day)		
Angola	Kizomba A	26.7	56	16	
	Girassol	16.7	34	31	33
	Xikomba	26.7	10	18	2
	Other	Various	28	6	
Australia	Various	15.8	36	36	40
Azerbaijan	Azeri-Chirag-Gunashli*	34.1	76	39	38
Canada	Various	Various	10	11	13
Colombia	Various	Various	41	48	53
Egypt	Various	Various	47	57	73
Trinidad & Tobago	Various	100.0	40	59	74
Venezuela	Various	Various	55	55	53
Other	Various	Various	26	31	49
Total Rest of World			459	407	428
Total Group (c)			1,423	1,480	1,615
Equity-accounted entities (BP Share)					
Abu Dhabi (b)	Various	Various	148	142	138
Argentina - Pan American Energy	Various	Various	67	64	60
Russia - TNK-BP (a)	Various	Various	911	831	296
Other	Various	Various	13	14	12
Total equity-accounted entities			1,139	1,051	506

* BP operated.

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Natural gas

Production	Field or Area	Interest	Year ended December 31, Net production 2005	2004	2003
		(%)	(million cubic feet per day)		
Lower 48 onshore (a)	San Juan*	Various	753	772	802
	Arkoma	Various	198	183	201
	Hugoton*	Various	151	158	182
	Tuscaloosa	Various	111	96	136
	Wamsutter*	70.5	110	105	111
	Jonah*	65.0	97	114	119
	Other	Various	465	514	558
Total Lower 48 onshore			1,885	1,942	2,109
Gulf of Mexico Deepwater (a)	Na Kika*	50.0	133	133	
	Marlin*	78.2	52	43	93
	Other	Various	235	313	470
Gulf of Mexico Shelf (a)	Other	Various	160	240	373
Total Gulf of Mexico			580	729	936
Alaska	Various	Various	81	78	83
Total USA			2,546	2,749	3,128
UK offshore (a)	Braes	Various	165	147	174
	Bruce*	37.0	161	163	222
	West Sole*	100.0	55	67	73
	Marnock*	62.0	47	70	98
	Britannia	9.0	46	54	55
	Shearwater	27.5	37	76	70
	Armada	18.2	30	50	58
	Other	Various	549	547	696
Total UK			1,090	1,174	1,446
Netherlands	P/18-2*	48.7	25	34	30
	Other	Various	37	46	37
Norway (a)	Various	Various	46	45	52
Total Rest of Europe			108	125	119

* BP operated.

Includes 4 million and 7 million cubic feet a day of natural gas received as in-kind tariff payments in 2005 and 2004, respectively.

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			Year ended December 31,		
			Net production		
Production	**Field or Area**	**Interest**	**2005**	**2004**	**2003**
		(%)	**(million cubic feet per day)**		
Australia	Various	15.8	367	308	285
Canada	Various	Various	307	349	422
China	Yacheng*	34.3	98	99	74
Egypt	Ha py*	50.0	106	80	83
	Other	Various	83	115	170
Indonesia	Sanga-Sanga (direct)*	26.3	110	137	165
	Other*	46.0	128	144	218
Sharjah	Sajaa*	40.0	113	103	101
	Other	40.0	10	14	19
Trinidad & Tobago	Kapok*	100.0	1,005	553	79
	Mahogany*	100.0	303	453	503
	Amherstia*	100.0	289	408	624
	Parang*	100.0	154	137	152
	Immortelle*	100.0	132	172	235
	Cassia*	100.0	83	85	30
	Other*	100.0	21	111	71
Other (a)	Various	Various	459	308	168
Total Rest of World			3,768	3,576	3,399
Total Group (d)			7,512	7,624	8,092
Equity-accounted entities (BP Share)					
Argentina - Pan American Energy	Various	Various	343	317	281
Russia - TNK-BP (a)	Various	Various	482	458	129
Other	Various	Various	87	104	111
Total equity-accounted entities (d)			912	879	521

* BP operated

(a) In 2005, BP divested the Teak, Samaan and Poui assets in Trinidad and sold interests in certain properties in the Gulf of Mexico. In addition, BP exchanged the Gulf of Mexico Deepwater Blind Faith prospect for Kerr McGee s interest in the Arkoma Red Oak and Williburton fields. TNK-BP disposed of non-core producing assets in the Saratov region. 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, Canada, and the Kangean PSA 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.

(b) The BP Group holds proportionate interests, through associates, 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 58 thousand barrels per day (mb/d), 67 mb/d and 70 mb/d for 2005, 2004 and 2003, 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

2005 liquids production at 612 thousand barrels per day (mb/d) decreased 8% from 2004, while natural gas production at 2,546 million cubic feet per day (mmcf/d) decreased 7% compared with 2004.

Hurricanes Katrina and Rita passed through the Gulf of Mexico in August and September, 2005, respectively, requiring the shut-in of all deepwater and shelf facilities. BP s production was significantly affected. The hurricanes resulted in heavy damage to operated and non-operated assets in both our upstream and midstream activities.

Crude oil production decreased 54 mb/d from 2004, with production from new projects being offset by the impact of hurricanes Dennis, Katrina and Rita and natural reservoir decline. The decline in the NGLs component of liquids production (17 mb/d) was primarily caused by the impact of hurricanes. Gas production was lower (203 mmcf/d) because of hurricanes Katrina and Rita, divestments, and natural reservoir decline.

Development expenditure in the USA (excluding midstream) during 2005 was $2,965 million, compared with $3,247 million in 2004 and $3,476 million in 2003. The annual decrease is the result of various development projects being completed.

Our activities within the United States take place in four main areas. Significant events during 2005 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 2005, our deepwater Gulf of Mexico crude oil production was 198 mb/d and gas production was 420 mmcf/d.

Significant events were:

In July 2005, stability problems impacted the Thunder Horse platform (BP 75% and operator). We concluded that this was caused by an issue with the ballast system. Repairs have been completed offshore and remaining construction has progressed with the installation of the risers. During routine pre-start-up testing, we have experienced problems with the subsea equipment. Investigations are ongoing, and pending the results, production is planned for the second half of 2006.

The Mars platform (BP 28.5%) suffered heavy damage from hurricane Katrina. Production, which resumed in May 2006, is expected to be restored to pre-Katrina rates by the middle of 2006.

Production from the Holstein field (BP 50% and operator) commenced in December 2004 and increased during 2005. The facility is designed to produce more than 100 mb/d of oil and 150 mmscf/d of gas.

Production from the Mad Dog facility (BP 60.5% and operator) commenced in January 2005. The facility is designed to process approximately 100 mb/d of oil and 60 mmscf/d of gas.

During 2005, a number of new discoveries were made in the deepwater Gulf of Mexico.

Development of other major projects continued in the Gulf of Mexico during 2005 Atlantis (BP 56% and operator) is scheduled to commence production around the end of 2006 followed by the King

Sub-sea Pump project (BP 100% and operator) in late 2007. These projects, including Thunder Horse, are expected to add over 200 mboe/d to our Gulf of Mexico production over the next two years.

Gulf of Mexico Shelf

The Shelf is a mature basin, with decline rates that average greater than 30% per year. Our gas production from Gulf of Mexico Shelf operations was 160 mmcf/d in 2005, down 33% compared to 2004. Liquids production was 16 mb/d, down 33% compared to 2004. The year-on-year decline in production was the result of normal decline and the effects of hurricanes Katrina and Rita.

BP s shelf operations suffered significant damage from hurricanes Katrina and Rita, including seven toppled platforms and an additional three platforms leaning, out of a total of 105, and flooding of onshore tanks and pumps. An impairment charge of $208 million was recognized in 2005 related to hurricane damage.

On April 19, 2006, BP announced the sale of its producing properties on the Outer Continental Shelf of the Gulf of Mexico to Apache Corporation for $1.3 billion. The properties are in waters less than 1,200 feet deep and include 18 producing fields (11 which are operated) covering 92 blocks with estimated reserves of 59 million barrels of oil equivalent and average daily production of 27 mboe. Completion of the sale is expected in mid-2006 once regulatory approvals have been received.

Lower 48 States

In the Lower 48 States (Onshore), our 2005 natural gas production was 1,885 mmcf/d, which was down 3% compared to 2004. Liquids production was 130 mb/d, down 8% compared to 2004. The year-on-year decrease in production is attributed to normal decline. In 2005, 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 214 mboe/d in 2005.

- In the Gulf Coast and Mid-Continental basins (Kansas, Louisiana, Oklahoma and Texas) our assets produced 183 mboe/d in 2005.

Significant events were:

- On February 1, 2005 we completed the acquisition of Kerr McGee s interests in the Arkoma Red Oak and Williburton fields in exchange for our Deepwater Gulf of Mexico Blind Faith prospect.

- In October 2005, we announced the investment of $2.2 billion in the expansion of the Wamsutter natural gas field. The multi-year drilling programme is expected to double production from 125 mmscf/d to 250 mmscf/d by the end of 2010. This project is part of a projected 10-year, $15 billion investment program for North America onshore operations.

- The development of recovery technology continues to be a fundamental strategy in accessing our North America tight gas resources. Through the use of horizontal drilling and advanced hydraulic fracturing techniques, we are achieving well rates up to ten times higher than more conventional techniques and per-well recoveries some five times higher.

Alaska

In Alaska, BP net crude oil production in 2005 was 268 mb/d, a decrease of 9% from 2004 due to mature field decline and operational issues partially offset by the development of satellite fields around Prudhoe Bay and Kuparuk and the restart of the Badami field.

Significant events were:

Maximizing productivity through active reservoir management of the fields we operate remains an essential part of the Alaska business. In 2005, BP operated drilling activity across the North Slope totalling 8.3 rig-years. Prudhoe Bay, and the associated satellite fields (BP 26.4% and operator) maintained an active infill and new well drilling programme with 75 wells in 2005, which generated net production of 4.9 mboe/d. The Northstar Unit drilled 2 wells in 2005, increasing net production by 2.6 mboe/d.

Developing viscous oil is an important part of the Alaska business. We are continually looking to develop viscous oil production in various fields through the application of advanced technology.

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 which is still awaiting resolution.

On December 19, 2005, the Alaska Gasline Port Authority filed a lawsuit against BP and ExxonMobil alleging violation of antitrust laws. BP denied the allegations. In an order dated June 19, 2006, the United States District Court for Alaska dismissed the Alaska Gasline Port Authority s antitrust lawsuit against BP and Exxon Mobil.

Negotiations on the Gas Pipeline fiscal contract with the State of Alaska continued during 2005. In February 2006, the gas portion of the fiscal contract was agreed in principle with the State Administration. BP and the other project sponsors are actively engaged with the Alaska Legislature toward the development of a new oil tax structure that will support a healthy oil and gas business in Alaska.

On March 2, 2006, a transit pipeline in the Prudhoe Bay field was discovered to have spilled an estimated 4,200 to 4,800 bbls of crude oil over approximately two acres. The processing facility that feeds into the transit line was immediately shut down. An investigation team has determined that the leak was caused by internal corrosion. Spill clean-up is complete and business operations have resumed using a separate bypass line. See also Environmental Protection Health, Safety and Environmental Regulation in this Item on page 68.

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 2005, total liquids production was 277 mb/d, a 16% decrease on 2004, and gas production was 1,090 mmscf/d, a 7% decrease on 2004. This decrease in production was driven by the natural decline of the mature North Sea basin combined with planned maintenance shutdowns partially offset by production from new projects. Our activities in the North Sea are focused on operations efficiency, in-field drilling and selected new field developments. Our development expenditure (excluding midstream) in the UK was $790 million in 2005 compared to $679 million in 2004 and $740 million in 2003.

Significant events were:

The Clair Phase 1 development (BP 28.6% and operator) produced first oil in February 2005. Drilling continues as part of the development programme.

The Rhum project (BP 50% and operator) produced first gas in December 2005. This was the UK s largest undeveloped gas discovery with initial production of 130 mmscf/d.

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In November 2005, BP achieved first oil in the $130 million development of the Farragon oil discovery (BP 50% and and operator), less than one year after Department of Trade and Industry (DTI) approval. The project is expected to achieve peak production at 18 mb/d.

Progress continued on the Magnus Expansion Project (BP 85% and operator) with first oil expected in the second half of 2006.

Drilling commenced in the first quarter of 2006 on the Schiehallion North West Area development project (BP 33.4% and operator). Three new wells will be drilled in the programme with first production expected by the end of 2006.

BP, on behalf of the owners of North West Hutton (BP 26% and operator), submitted the proposed decommissioning programme to the DTI in November 2004. The proposal is still under review with platform removal expected to begin between 2007 and 2009.

In December 2005, the UK government announced a 10% supplemental tax increase on North Sea oil profits, taking the total corporate tax rate to 50%. If this proposal is confirmed by the legislative process it is expected to have retroactive effect from January 1, 2006.

In March 2006, we reached agreement for the sale of our 4.84% interest in the Statfjord oil and gas field. Completion of this sale is expected in the middle of 2006.

Rest of Europe

Development expenditure, excluding midstream, in the Rest of Europe was $188 million compared with $262 million in 2004 and $236 million in 2003.

Norway

In 2005, total Norway production was 82 mboe/d, a 2% decrease on 2004. This decrease in production was driven by natural decline partly offset by high operational efficiency on the BP operated Ula and Valhall fields.

Significant activities were:

On February 28, 2005 we completed the sale of our 10.3% interest in the Ormen Lange development and our 10.2% interest in the Langeled gas export pipeline to the Danish utility company, DONG.

Progress on the Valhall (BP 28.1% and operator) redevelopment project continued during 2005. A new platform is scheduled to become operational in 2009 with expected oil production capacity of 250 mb/d and gas handling capacity of 175 mmscf/d.

In March 2006, we reached agreement for the sale of our interest in the Luva gas discovery, in the North Sea. This sale was completed in the second quarter of 2006.

Netherlands

In May 2006, we announced our intention to sell our exploration and production and gas infrastructure business in the Netherlands. This includes onshore and offshore production assets and the onshore gas supply facility, Piek Gas Installatie, at Alkmaar. The sale is expected to be completed by the end of 2006, subject to consultation with the Works Council.

Rest of World

Development expenditure, excluding midstream, in Rest of World was $3,735 million in 2005 compared with $3,082 million in 2004 and $3,085 million in 2003. We discuss the significant events and developments under each section below.

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Rest of Americas

Canada

In Canada, our natural gas and liquids production was 63 mboe/d in 2005, a decrease of 11% compared to 2004. The year-on-year decrease in production is mainly due to natural field decline.

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 3%, to 1,987 mmscf/d in 2005. The increase was principally driven by a full year of gas supply to the Atlas Methanol plant (initial start-up was in the third quarter 2004). Liquids production declined by 19 mb/d (32%), to 40 mb/d in 2005 mainly due to the divestment of the Teak, Samaan and Poui (TSP) fields and natural decline.

Cannonball, Trinidad s first major offshore construction project executed locally, started production in March 2006. Cannonball is currently providing gas for Atlantic LNG Train 4 (BP 37.8%), which commenced liquefaction in December 2005.

In November 2005, we completed the sale of the TSP oil fields to Repsol YPF and the government of Trinidad. At the time of the sale, the TSP fields produced approximately 20.5 mboe/d which represented five per cent of Trinidad s production of oil and gas.

Venezuela

In Venezuela, our 2005 liquids production remained unchanged at 55 mb/d compared to 2004. Three of BP s 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 Operating Service Agreements to produce oil for the state oil company, Petroleos de Venezuela S.A. (PDVSA). 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 March 2006, BP signed Memoranda of Understanding to cooperate with PDVSA in setting up incorporated joint ventures in which PDVSA would be the majority shareholder. The incorporated joint ventures would become the operators of the Boqueron and DZO properties. It is expected that these arrangements will be finalized in the second half of 2006. The operator of Jusepin is aiming to enter into a similar agreement on behalf of the partners, including BP.

In 2005, changes were made by the Venezuelan government to increase corporate income taxes on Oil Service Companies from 34% to 50%. In 2006, proposals have also been made by the government to increase corporate income taxes on Oil Extraction Companies from 34% to 50%, and to introduce a new Extraction Tax at a maximum rate of 33.33% (the existing royalty of 16.67% is expected to be offset against the new Extraction Tax).

In March 2006, we settled for $14 million a dispute with the tax authorities regarding taxes on previous production.

Colombia

In Colombia, BP s net production averaged 55 mboe/d. The main part of the 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. In March 2006, cumulative production from the BP operated fields reached 1 billion barrels since operations began in 1992.

During 2005, the upgrade of the existing gas processing facilities (BP 24.8%) was completed, resulting in increased capacity from 40 to 180 mmscf/d.

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 2005, total production of 136 mboe/d represented an increase of 5% over 2004, with oil increasing by 3% and gas by 7%. 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 58 mb/d compared to 56 mb/d in 2004. 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. The tax was effective from May 19, 2005 and foreign oil and gas companies are required to sign new contracts conforming with the new law.

In May 2006, the Bolivian government announced its intention to change contractual arrangements with foreign oil companies. The transitional arrangements are still being negotiated and the impact of these changes is being assessed.

Africa

Algeria

BP, through its joint operatorship of In Salah Gas with Statoil and the Algerian state company, Sonatrach, supplied 318 bcf (gross) of gas to markets in southern Europe during its first full year of production and started operations of the carbon dioxide (CO_2) capture system as part of the In Salah project (BP 33.15%). This is one of the world s largest CO_2 capture projects, providing emissions savings estimated to be equivalent to taking a quarter of a million cars off the road.

BP, through its joint operatorship of In Amenas with Statoil and Sonatrach, continued to progress the development of the In Amenas project (BP 12.5%). First production was achieved in June 2006.

Through Algeria s sixth international licensing round, BP was awarded three exploration blocks, South East Illizi, Bourarhat South and Hassi Matmat.

Angola

In Block 15 (BP 26.7%), Kizomba B commenced production in July 2005, four months ahead of schedule. Development of Kizomba C commenced in the first quarter of 2006.

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. Development on the Rosa project, a tie-back to Girassol hub, continued with first production planned for late 2007.

In Block 18 (BP 50% and operator), work has continued on the Greater Plutonio development in line with expectations to commence production in 2007.

In Block 31 (BP 26.7% and operator), a further four discoveries were made in 2005 and a further discovery was announced in 2006. There have been a total of ten discoveries that are at various stages of assessment of commercial viability.

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 operated oil and

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gas production operations. GUPCO operates eight PSAs in the Gulf of Suez and Western Desert and one PSA in the Mediterranean Sea encompassing more than forty fields.

Following the blow-out and subsequent fire on the partner-operated Temsah North West platform (BP 50%) in the third quarter of 2004, the Temsah redevelopment progressed during 2005 with drilling completed in December. The project achieved first production ahead of schedule in the second quarter of 2006.

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.

In the first quarter of 2005, BP sanctioned investment in the Saqqara field (BP 100%). The project is the development of the largest recent exploration success in Gulf of Suez. First production is expected in late 2007.

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 Agreement (BP 46%).

During 2005, progress continued on the Tangguh LNG project (BP 37.2% and operator). The project development includes offshore platforms, pipelines and an LNG plant with two production trains. First gas is expected in late 2008.

Vietnam

BP participates in the country s largest project with 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. In 2005, natural gas production was 346 mmcf/d gross, an increase of 39% over 2004. This increase was mainly due to high demand in the first half of the year as a result of an extended drought, which impacted hydro utilization. Gas sales from Block 6.1 (BP 35% and operator) are made under a long-term agreement for electricity generation in Vietnam, including the Phu My Phase 3 power plant (BP 33.33%).

From January 1, 2006 BP s interest in the Phu My Phase 3 power plant has been transferred to the Gas, Power and Renewables segment.

China

The Yacheng offshore gas 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 in the North West Shelf (NWS) Venture. Each partner holds a 16.7% interest in the infrastructure and oil reserves and a 15.8% interest in the gas reserves and condensate. 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 2005, a fifth LNG Train (4.7 million tonnes per annum design capacity) was sanctioned with first throughput expected in late 2008.

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Russia

TNK-BP

TNK-BP (BP 50%) is an integrated oil company operating in Russia and the Ukraine. TNK-BP has proved reserves of 4.7 billion boe (including its 49.5% equity share of Slavneft), of which 3.8 billion are developed. In 2005, average liquids production was 1.8 million boe/d, an increase of just under 10% over 2004. Total production, including gas, exceeded 2 million boe/d for the first time in the third quarter of 2005. The production base is largely centered in West Siberia (Samotlor, Nizhnevartovskoye Neftedobyvarshee Predpriyatie, Nyagan and Megion), which contributes about 1.4 million boe/d, together with Volga Urals (Orenburg) contributing 0.4 million boe/d. About 55% of total oil production is currently exported as crude oil and 20% as refined product. Downstream, TNK-BP owns five 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 90,000 people.

In December 2005, TNK-BP disposed of non-core producing assets in the Saratov region, along with the Orsk refinery and certain TNK-BP operated petrol stations. The disposals allow TNK-BP to streamline its operations and concentrate on strategic investments in projects with high-growth potential. This includes further extension drilling in the Ust Vakh area of the Samotlor field and in the Kamenoye field, as well as the greenfield Demiansky project in the Uvat area.

Various TNK-BP companies have received tax notifications. Upon entering into the joint venture arrangement, each party received indemnities from its co-venturers in respect of historical tax liabilities related to assets contributed to the joint venture. BP believes existing provisions are adequate for its share of any liabilities arising from tax claims not covered by these indemnities.

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.

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. In September 2005, the voluntary exchange programme was completed with approximately 70% participation. In December 2005, the restructuring was completed with the accession of OAO ONAKO to OAO TNK-BP Holding. The restructuring has resulted in OAO TNK-BP Holding owning 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. TNK-BP will consider further accessions of material subsidiaries if these are believed to provide organizational advantages.

On June 20, 2006 TNK-BP announced its intent to sell its interest in OAO Udmurtneft to Sinopec subject to various conditions.

Sakhalin

BP participates in exploration activity through Elvaryneftegas (BP 49%), a joint venture with Rosneft. A first discovery was made in Sakhalin in October 2004, followed by a second in October 2005. Further exploratory drilling is planned during 2006.

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Other

Middle East and Pakistan

Production in the Middle East principally consists of the production entitlement of associates in Abu Dhabi, where we have equity interests of 9.5% and 14.7% in onshore and offshore concessions, respectively. In 2005, production in Abu Dhabi was 148 mb/d, up 4% from 2004 as a result of capacity enhancements and strong worldwide demand.

In Pakistan, BP is one of the leading foreign operators producing 22% of the country s oil and 6% of its natural gas on a gross basis in 2005.

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 and West Azeri to Sangachal terminal on March 3, 2005 and January 3, 2006 respectively. Successive phases of the project include East Azeri scheduled to come on stream in 2007 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) remains on track to deliver first gas during the second half of 2006. The fourth and final pre-drill well was successfully suspended in January 2006, completing the Stage 1 pre-drill programme. The assembly and installation of the modules and associated equipment for the platform was completed in the first quarter of 2006 and installed on location in April. Commissioning and tie-in work for the platform, terminal and the South Caucasus Pipeline export pipelines is currently underway.

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 2005 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 895 mb/d during 2005.

Work progressed during 2005 on the strategic reconfiguration project to upgrade and automate four pump stations. This project will install electrically driven pumps at four critical pump stations, combined with increased automation and upgraded control systems. Startup of the reconfigured system is expected to occur in the fourth quarter of 2006.

In December 2005, TAPS reached an operational milestone of transporting its 15 billionth barrel of oil.

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). These matters are proceeding through the Alaska judicial and regulatory systems. Pending the resolution of these matters the RCA has imposed intrastate rates effective July 1, 2003 that are consistent with its 2002 Order requiring refunds to be made to TAPS shippers of intra-state crude oil.

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 February 2006, FERC combined and consolidated all 2005 and 2006 rate complaints filed by the State, Anadarko, Tesoro and Tesoro Alaska. The complaints were filed on a variety of grounds. We are confident that the rates are in accordance with the TSM and are continuing to evaluate the disputes.

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 70. 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, the second, the Alaskan Explorer, in March 2005 and the third, the Alaskan Navigator, in November 2005. The fourth is expected to be delivered in the second half of 2006.

North Sea

FPS (BP 100%) is an integrated oil and NGLs transportation and processing system that handles production from over 50 fields in the Central North Sea. The system has a capacity of more than 1 mmb/d, with average throughput in 2005 at 622 mb/d.

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 2005, throughput was 1.14 bcf/d (gross), 336 mmcf/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. The 1,768 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. Filling of the pipeline progressed during 2005 and loading of the first tanker at Ceyhan occurred in June 2006.

The South Caucasus Pipeline for the transport of gas from Shah Deniz in Azerbaijan to the Turkish border is substantially complete. The pipeline is expected to be ready to receive first gas in the second half of 2006, in conjunction with the start-up of Shah Deniz gas field. 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 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 2005, CPC total throughput reached 30.5 million tonnes. During 2005, negotiations continued between the CPC shareholders toward the approval of an expansion plan. The expansion will require the construction of ten additional pump stations, additional storage facilities and a third offshore mooring point.

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 63). BP Exploration and Production has interests in four major LNG plants. The Atlantic LNG plant in Trinidad (BP 34% in Train 1, 42.5% 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% infrastructure and oil reserves/15.8% gas and condensate reserves).

Significant activities during 2005 included the following:

We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2005 supplied 5.4 million tonnes (280 bcf) of LNG, down 8.5% on 2004.

In Australia, we are one of six equal partners in the NWS Venture. Each partner holds a 16.7% interest in the infrastructure and oil reserves and a 15.8% interest in the gas reserves and condensate. The joint venture operation covers offshore production platforms, a floating production and storage vessel, trunklines, onshore gas processing plants and LNG carriers. In June 2005, we approved our investment in a fifth LNG train that is expected to process 4.7 million tonnes of LNG a year and will increase the plant s capacity to 16.6 million tonnes a year. Construction started in July 2005 and the train is expected to be commissioned during the second half of 2008. NWS produced 11.7 million tonnes (533 bcf) of LNG, an increase of 26% on 2004.

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 currently delivers around 17% of the total gas feed to Bontang, one of the world s largest LNG plants. The Bontang plant produced 19.4 million tonnes (905 bcf) of LNG in 2005, a reduction of 1% on 2004.

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 of the Atlantic LNG Train 4 (BP 37.8%) was completed in December 2005 with the first LNG cargo delivered in January 2006. Train 4 is now the largest producing LNG train in the world and 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. BP s net share of the capacity of Atlantic LNG Trains 1, 2, 3 and 4 is 6.5 million tonnes (305 bcf) of LNG per annum.

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REFINING AND MARKETING

Our Refining and Marketing business is responsible for the supply and trading, refining, marketing and transportation of crude oil, petroleum and chemical 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.

	Year ended December 31,		
	2005	2004	2003
		($ million)	
Sales and other operating revenues for continuing operations	213,465	170,749	143,441
Profit before interest and tax from continuing operations (a)	6,442	6,544	3,235
Total assets	77,352	73,581	67,546
Capital expenditure and acquisitions	2,772	2,819	3,019
		($ per barrel)	
Global Indicator Refining Margin (b)	8.60	6.31	4.08

(a) Includes profit after interest and tax of equity-accounted entities.

(b) The Global Indicator Refining Margin (GIM) is the average of 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.

The changes in sales and other operating revenues are explained in more detail below:

		Year ended December 31,		
		2005	2004	2003
Sale of crude oil through spot and term contracts	($ million)	36,992	21,989	22,224
Marketing, spot and term sales of refined products	($ million)	155,098	124,458	102,003
Other sales including non-oil and to other segments	($ million)	21,375	24,302	19,214
		213,465	170,749	143,441
Sale of crude oil through spot and term contracts	(mb/d)	2,464	2,312	2,387
Marketing, spot and term sales of refined products	(mb/d)	5,888	6,398	6,688

There are five areas of business in Refining and Marketing: Refining, Retail, Lubricants, Business to Business Marketing and Aromatics and Acetyls. Our strategy is to continue our focused investment in key assets and market positions. We aim to improve the quality and capability of our manufacturing portfolio. Our marketing businesses, underpinned by world-class manufacturing, generate customer value by providing quality products and offers. Our retail strategy provides differentiated fuel and convenience offers to some of the most attractive global markets. Our lubricants brands offer customers benefits through technology and relationships, and we focus on increasing brand and product loyalty in Castrol lubricants. We continue to build deep customer relationships and strategic partnerships in the business to business sector.

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 (e.g. refinery proximity to market), 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. Refining and Marketing also includes the Aromatics and Acetyls business which maintains manufacturing positions globally, with an emphasis on Asia growth, particularly in China.

BP received citations from the US Occupational Safety and Health Administration (OSHA) in respect of the Texas City, Texas and Toledo, Ohio refineries. See Item 4 Environmental Protection Health, Safety and Environmental Regulation in this Item on page 68.

As a result of the sale of Innovene to INEOS, contracts were put in place for the sale and purchase of hydrocarbons, utilities and services between BP and INEOS, principally in the USA, UK, France, Belgium and the Netherlands. Agreements are in place between BP Refining and Marketing and INEOS at the Carson, Nerefco, Texas City, Toledo and Whiting refineries and the Geel chemical plant.

In June 2006, we announced our intention to sell the Coryton Refinery in the UK, which processes 172,000 barrels of crude oil a day.

In November 2005, BP and Sinopec established BP YPC Acetyls Company (BP 50%), a 500 thousand tonnes per annum (ktepa) acetic acid joint venture in Nanjing, China. The two companies previously signed a heads of agreement in May 2004 and a joint venture contract in March 2005. This world-scale joint venture is expected to be on stream at the end of 2007.

BP announced plans for a second purified terephthalic acid (PTA) plant at the BP Zhuhai Chemical Company Limited site in Guangdong Province, China, which received approval from the Chinese government in April 2006. The new plant will have operating capacity of 900,000 ktepa and is expected to come on stream at the end of 2007. It will be the first plant to use BP s latest generation PTA technology.

The transaction announced in 2004 for the sale of BP s 70% shareholding in BP Malaysia Sdn Bhd to Lembaga Tabung Angkatan Tentera (LTAT) was successfully concluded during 2005 and the disposal to Österreichische Mineralöl Verwaltung Aktiengesellschaft (OMV) of BP s network of 70 retail sites in the Czech Republic, announced in October 2005, was completed in early 2006.

Resegmentation in 2006

Since the end of 2005, BP has made a number of organizational changes. With effect from January 1, 2006:

- Following the sale of Innovene to INEOS, the Shanghai SECCO Petrochemical Company Limited and Malaysia joint ventures, previously held in Other Businesses and Corporate, were transferred to Refining and Marketing.

- The formation of BP Alternative Energy has resulted in the transfer of certain mid-stream assets and activities to and from Gas, Power and Renewables:
  - South Houston Green Power Cogeneration facility (in Texas City refinery) from Refining and Marketing to Gas, Power and Renewables.
  - Watson Cogeneration facility (in Carson refinery) from Refining and Marketing to Gas, Power and Renewables.
  - Transfer of Hydrogen for Transport from Gas, Power and Renewables to Refining and Marketing.

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Texas City Refinery

On March 23, 2005, an explosion and fire occurred in the Isomerization Unit of BP Products North America, Inc. s (BP Products) Texas City refinery as the unit was coming out of planned maintenance. Fifteen contractors died in the incident. Other contractors and employees were injured. In the third quarter of 2005, Texas City was the subject of a settlement with the U.S. Occupational Safety and Health Administration (OSHA), as BP Products and OSHA announced a settlement following OSHA s investigations at the Texas City refinery after the March 23, 2005 explosion and fire. During 2005, BP Products made a provision of $700 million for fatality and personal injury compensation claims associated with the incident at its Texas City refinery. Following a review during the second quarter of 2006, an additional provision of $500 million was made which is reflected in the financial statements for the year ended December 31, 2005. See Item 18 Financial Statements Note 43 on page F-114.

OSHA issued its citations alleging more than 300 violations of 13 different OSHA standards, and BP Products has agreed not to contest the citations. BP Products paid a $21.3 million fine and has undertaken a number of corrective actions designed to make the refinery safer. The settlement agreement addresses not only the March 23, incident, but also closes out other OSHA investigations at the refinery.

BP Products has agreed to:

- Hire a process safety expert at the refinery to review safety programs, offer recommendations and provide reports on the refinery s progress;
- Hire an organizational expert at the refinery to study the refinery s communication with respect to safety and commitment to safety and to offer recommendations for improvement;
- Improve health and safety training; and
- Develop an abatement plan addressing other corrective measures.

During 2005, the US Chemical Safety and Hazard Investigation Board recommended that BP appoint an independent panel to study the safety systems and cultures at its US refineries. BP s chief executive, Lord Browne, commissioned a panel of eminent experts under the chairmanship of former US Secretary of State, James A Baker III, pursuant to this recommendation. BP is committed to providing complete co-operation to the Panel in support of this review. The Panel is expected to complete the review and present recommendations prior to the end of 2006. See also Environmental Protection Health, Safety and Environmental Regulation in this Item on page 68 and Item 8 Financial Information Legal Proceedings on page 148.

In September 2005, hurricane Rita threatened the Texas City Refinery necessitating an entire plant shutdown. Hurricane Rita ultimately took a turn away from the refinery but the precautionary shutdown of an adjacent cogeneration facility, which provides the steam supply to the refinery, resulted in thermal cycling and damage to the Texas City plant s 27-mile steam system. This damage required extensive repair and maintenance to the steam system and on many gasoline production units. At the end of the year the plant s steam system was restarted. Initial hydrocarbon production commenced at the end of March and ongoing recommissioning is planned to continue in a phased manner over the remainder of the year.

The site-wide shutdown of the Texas City refinery also impacted the Aromatics and Acetyls business co-located manufacturing capacity of paraxylenes (PX) and metaxylene. The PX unit resumed production in March and the metaxylene unit resumed in April, 2006. The remaining PX capacity at Texas City is expected to restart in line with the ongoing recommissioning of the refining units in a phased manner during 2006.

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Refining

The Company s global refining strategy is to own interests in and to operate strategically advantaged refineries that benefit from vertical integration with our marketing and trading operations as well as 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. Following the transfer of the Lavera, France and Grangemouth, UK, refineries from Refining and Marketing to Other businesses and corporate, effective January 1, 2005, our refining portfolio is weighted more heavily to the US, where margins are structurally higher.

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The following table summarizes the BP Group interests and crude distillation capacities at December 31, 2005:

	Refinery	Group interest (b) %	Crude distillation capacities (a) (mb/d) Total	BP share
UK	Coryton*	100.00	172	172
Total UK			172	172
Rest of Europe				
France	Reichstett	17.00	84	14
Germany	Bayernoil	22.50	269	62
	Gelsenkirchen*	50.00	270	135
	Karlsruhe	12.00	308	37
	Lingen*	100.00	91	91
	Schwedt	18.75	230	43
Netherlands	Nerefco*	69.00	400	276
Spain	Castellón*	100.00	110	110
Total Rest of Europe			1,762	768
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	475	475
Total USA			1,527	1,527
Rest of World				
Australia	Bulwer*	100.00	97	97
	Kwinana*	100.00	137	137
New Zealand	Whangerei	23.66	107	25
Kenya	Mombasa	17.00	90	15
South Africa	Durban	50.00	182	91
Total Rest of World			613	365
Total			4,074	2,832

* 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.

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

	Year ended December 31,		
Refinery throughputs (a)	**2005**	**2004**	**2003**
	(thousand barrel per day)		
UK	180	208	202
Rest of Europe	667	684	753
USA	1,255	1,373	1,386
Rest of World	297	342	382
Total	2,399	2,607	2,723
Refinery capacity utilization			
Crude distillation capacity at December 31 (b)	2,832	2,823	2,983
Crude distillation capacity utilization (c)	87%	93%	91%
USA	82%	95%	91%
Europe	90%	90%	90%
Rest of World	88%	87%	94%

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

(b) Crude distillation capacity is gross rated capacity which 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 2005 refinery throughput decreased in the UK and Rest of Europe compared with 2004 primarily due to the transfer of the Grangemouth and Lavéra refineries from Refining and Marketing to the Olefins and Derivatives business reported within Other businesses and corporate, effective January 1, 2005. The decrease in the USA in 2005 was largely due to the impact of the shutdown of Texas City after hurricane Rita.

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Marketing

Marketing comprises four business areas: Retail, Lubricants, Business to Business Marketing and Aromatics and Acetyls. We market a comprehensive range of refined products worldwide. These products include gasoline, gasoil, marine and aviation fuels, heating fuels, LPG, lubricants and bitumen. We also manufacture and market purified terephthalic acid, paraxylene, and acetic acid through our Aromatics and Acetyls business.

	Year ended December 31,		
Sales of refined products (a)	**2005**	**2004**	**2003**
	(thousand barrels per day)		
Marketing sales:			
UK (b)	355	322	275
Rest of Europe	1,354	1,360	1,308
USA	1,634	1,682	1,766
Rest of World	599	638	620
Total marketing sales (c)	3,942	4,002	3,969
Trading/supply sales (d)	1,946	2,396	2,719
Total refined products	5,888	6,398	6,688
	($ million)		
Proceeds from sale of refined products	155,098	124,458	102,002

(a) Excludes sales to other BP businesses and the sale of Aromatics and Acetyls products.

(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 sales to large unbranded resellers and other oil companies.

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

	Year ended December 31,		
Marketing sales by refined product	**2005**	**2004**	**2003**
	(thousand barrels per day)		
Aviation fuel	499	494	530
Gasolines	1,603	1,675	1,714
Middle distillates	1,185	1,255	1,203
Fuel oil	379	343	296
Other products	276	235	226
Total marketing sales	3,942	4,002	3,969

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 costs 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.

Marketing sales of refined products were 3,942 mb/d in 2005, compared with 4,002 mb/d in the previous year. The decrease was due mainly to the effects of the price increases as a result of supply disruption and market uncertainty.

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BP enjoys a strong market share and leading technologies in the Aromatics and Acetyls business. In Asia, we continue to develop a strong position in PTA and acetic acids. Our investment is biased towards this high growth region, especially China.

Retail

Our retail strategy focuses on investment in high growth metropolitan markets and the upgrading of our retail offers while driving operational efficiencies through portfolio optimisation.

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 fuels offer is deployed at 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 impact. In 2004 and 2005, 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, Turkey, Australia and the US.

We continue to focus on operational efficiencies through targeted portfolio upgrades for performance improvement that have increased our fuel throughput per site and our store sales per square meter. In 2005, across the network, same store sales growth at 1.9% exceeded estimated market growth of 0.8%.

	Year ended December 31,		
Store sales (a)	**2005**	**2004**	**2003**
		($ million)	
UK	628	655	567
Rest of Europe	3,069	3,090	3,000
USA	1,776	1,715	1,620
Rest of World	610	601	521
Total	6,083	6,061	5,708
Direct-managed	2,489	2,319	2,090
Franchise	3,533	3,623	3,508
Store alliances	61	119	110
Total	6,083	6,061	5,708

(a) Store sales reported are sales through direct-managed stations, franchisees 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.

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Our retail network is largely concentrated in Europe and the USA, with established operations in Australasia and Southern and Eastern Africa. We are developing networks in China with joint venture partners.

	Year ended December 31,		
Retail Sites	**2005**	**2004**	**2003**
UK	1,300	1,300	1,300
Rest of Europe	7,900	8,000	8,200
USA (excluding jobbers)	3,100	3,900	4,100
USA jobbers	9,700	10,300	10,600
Rest of World	3,200	3,300	3,600
Total	25,200	26,800	27,800

BP s worldwide network consists of over 25,000 locations branded BP, Amoco, ARCO and Aral compared with approximately 27,000 in the previous year. We expect the total number of sites 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 2005, we sold 488 Company owned sites (including all company owned sites in the Las Vegas, Washington and Detroit metro region) to dealers and jobbers who continue to operate these sites under the BP brand. We also divested 129 Company owned sites in 2005 and announced the divestment of BP s Czech Republic retail network which was completed in early 2006.

In 2005, we continued the rollout of the BP Connect offer at sites in the UK and USA, consistent with our retail strategy of building on our advantaged locations, strong market positions and brand. The BP Connect sites include a distinctive food offer, large convenience store and a forecourt that provides our customers with cleaner fuels. The new BP Connect sites are those that are new to industry and those where extensive upgrading and remodeling has taken place. At December 31, 2005, over 630 BP Connect stations were open worldwide.

Through regular review and execution of business opportunities we continue to concentrate our ownership of real estate in markets designated for development of the convenience offer. At December 31, 2005, BP s retail network in the USA comprised approximately 12,800 sites, of which approximately 9,700 were owned by jobbers. In the UK and the Rest of Europe, BP s network comprised about 9,200 sites and 3,200 sites in the Rest of World.

The Joint Venture between BP and PetroChina (BP-PetroChina Petroleum Company Ltd) started operation in 2004. Located in Guangdong, one of the most developed provinces in China, 411 sites were operational at 31 December 2005. The JV plans to operate and manage a total network of 500 locations in the province. A Joint Venture with Sinopec, approved in the fourth quarter of 2004 with the establishment of BP-Sinopec (Zhejiang) Petroleum Co Ltd, commenced operations with 151 sites in Ningbo in 2005 with a further 71 sites transferred into the joint venture in May 2006. The JV plans to build, operate and manage a network of 500 sites in Hangzhou, Ningbo and Shaoxing.

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. 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, Veedol and Aral.

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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 and 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 marketing sales of around 26,832 million liters (approximately 456,000 bbl/day) and has key relationships with most of the major commercial airlines. AirBP s strategic aim is to strengthen its position in their existing markets (Europe/ US/ Asia Pacific) whilst creating opportunities in the emerging economies such as South America and China.

The LPG business sells bulk, bottled, automotive and wholesale products to a wide range of customers in over 16 countries. During the past few years, our LPG business has consolidated its position in established markets and pursued opportunities in new and emerging markets. BP remains one of the leading importers of LPG into the China market where we continued to grow our retail LPG business. LPG Marketing Product sales in 2005 were approximately 96,000 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 marine lubricants market leader and has a strong trading and bunker presence in the fuels market. The business has offices in 45 countries and operates in over 800 ports.

The Commercial Fuels business has activities in approximately 14 European countries and has marketing sales of approximately 616,000 bbl/day. The business markets fuels and heating oil, mostly as pick-up business at refineries, terminals and depots. As from 2006, this business will also manage the European Fleet services portfolio (serving commercial road transport customers).

Our Business to Business Marketing activities also include Industrial Lubricants (selling industrial lubricants and services to manufacturing companies in approximately 41 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.

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Aromatics and Acetyls

The Aromatics and Acetyls business is managed along three main products lines: PTA, PX, and Acetic Acid. PTA is a raw material for the manufacture of polyesters used in textiles, plastic bottles, fibres and films. PX is feedstock for the production of PTA. Acetic acid is a versatile chemical used in a variety of products such as paints, adhesives, and solvents. It is also used in the production of PTA. In addition to these three main products, we are involved in a number of other petrochemicals products namely napthalene dicarboxylate (NDC) which is used for photographic film and specialized packaging and ethyl acetate and vinyl acetate monomer (VAM) which are used in coatings and textile application.

Our Aromatics and Acetyls strategy is to invest to maintain our advantaged manufacturing positions globally, with an emphasis on Asia growth, particularly in China. We also work to advance our technology leadership position to yield both operating and capital cost advantages.

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The following table shows BP production capacity at December 31, 2005. This production capacity is based on original design capacity of the plants plus expansions.

Geographical Area	PTA	PX	Acetic Acid	Other	Total BP share of capacity	
			(thousand tonnes per year)			
UK						
Hull			677	664	1,341	
Rest of Europe						
Belgium						
Geel	1,044	520			1,564	
USA						
Cooper River	1,330				1,330	
Decatur	1,100	1,121		27	2,248	
Texas City		1,282	527(a)	122	1,931	
Rest of World						
Brazil						
São Paulo	143				143	(49% of Rhodiaco)
China						
Chongqing			169	52	221	(51% of YARACO) (b)
Zhuhai	583				583	
Indonesia						
Merak	250				250	(50% of PT Ami)
Korea						
Ulsan	550(c)		229(e)	56(d)	835	(47% of SPC) (c); (34% of ASACCO) (d); (51% of SS-BP) (e)
Seosan	339				339	(47% of SPC) (c)
Malaysia						
Kertih			544		544	
Kuantan	703				703	
Taiwan						
Kaohsiung	825				825	(61% of CAPCO) (f)
Taichung	458				458	(61% of CAPCO) (f)
Mai Liao			162		162	(50% of FBPC) (g)
	7,325	2,923	2,308	921	13,477	

(a) Sterling Chemicals plant, the output of which is marketed by BP.

(b) Yangtze River Acetyls Company.

(c) Samsung-Petrochemicals Company Ltd.

(d) Asian Acetyls Company Ltd.

(e) Samsung-BP Chemicals Ltd.

(f) China American Petrochemical Company Ltd.

(g) Formosa BP Chemicals Corporation.

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Further to the establishment of the BP YPC Acetyls Company and the plans for a second PTA plant at the BP Zhubai Chemical Company Limited site in Guandong Province, China, described previously, the following portfolio activity took place in the Aromatics and Acetyls business during the year:

Yangtze River Acetyls Company (BP 51%) completed an expansion project in Chongqing, China in the third quarter of 2005 which increased capacity to 350 ktepa.

A 300 ktepa acetic acid joint venture in Taiwan with Formosa Chemicals and Fibre Corporation (BP 50%) was successfully commissioned in December 2005.

BP has announced the phased closure of two acetic acid plants at Hull, UK due to lack of scale and outdated technology. Combined capacity of the two plants was 380 ktepa. The first plant was shut down in the second quarter of 2005 and the remaining plant is expected to be shut down later in 2006.

BP has announced that it is developing a 350 ktepa PTA expansion at Geel, Belgium. The project is expected to be operational in early 2008 and will increase the site PTA capacity to 1.4 ktepa.

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.

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 2003 to 2005.

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

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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 recognized 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 gas oil. 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 sales and other operating revenues for both IFRS and US GAAP.

(b) Over-the-counter (OTC) contracts

These contracts are typically in the form of forwards, swaps and options. OTC contracts are negotiated between two parties. They are not traded on an Exchange. These contracts can be used both as part of trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in sales and other operating revenues for both IFRS and US GAAP.

The main grades of crude oil bought and sold forward using standard contracts are West Texas Intermediate and a standard North Sea crude blend (Brent, Forties and Osberg BFO). Although the contracts 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.

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. Amounts under these derivative financial instruments are settled at expiry, typically through netting agreements, to limit credit exposure and support liquidity.

(c) 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 IFRS and US GAAP, spot and term sales are included in sales and other operating revenues, when title passes. Similarly, spot and term purchases are included in purchases for IFRS and US GAAP.

Refer to Item 11 Quantitative and Qualitative Disclosures About Market Risk on page 162 for further information.

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Transportation

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

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 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

We transport our products across the world s oceans and along coastlines using a combination of BP operated vessels, time chartered and spot chartered vessels. In 2005, we continued to implement our strategy of increasing our operated shipping fleet in order to manage more effectively the risk of a major oil spill. This fleet transformation is ahead of the international requirements for phase-out of single-hulled vessels. See Environmental Protection Maritime Oil Spill Regulations in this Item on page 70.

International Fleet

In 2004, we managed an international fleet of 42 vessels including 34 Oil Tankers and eight LNG Gas Carriers. At the end of 2005 we had 52 international fleet vessels including 39 Medium Size Crude Carriers, four Very Large Crude Carriers, one North Sea Shuttle Tanker and eight LNG Gas Carriers. All of these are double-hulled. Of the eight LNG Carriers, BP manages five on behalf of joint ventures in which it is a participant and operates three LNG Carriers with a further four on order.

Regional and Specialist Vessels

In addition to the international fleet we took delivery of a new double-hulled lube oil barge, three tugs and two offshore support vessels in 2005, to support BP businesses.

In Alaska, the leases on four vessels expired. We have taken delivery of the second and third of a four ship series of state of the art double-hulled tankers; the fourth and final one to be delivered into service later in 2006. The entire Alaska fleet of six vessels is now double-hulled.

The phase-out plan for the four heritage Amoco barges in the US was finalized in 2005 for completion in 2007.

Time Charter Vessels

BP has 81 vessels on time charter, of which 66 are double-hulled and three double-bottomed. All of these vessels are enrolled in BP s Time Charter Assurance programme which requires compliance with our HSSE requirements. We also spot charter additional vessels which are vetted prior to use to ensure they meet our safety and integrity standards.

The majority of our coastal vessels are time chartered. For example, in the UK, we completed the phase out of our single-hull tankers and replaced them with three new double-hulled coastal tankers on long term time charter.

For Greek and Turkish coastal trades, BP has partnered with two high-quality local operators and entered into time charters to provide ten new-build double-hulled coastal tankers.

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GAS, POWER AND RENEWABLES

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

i. To capture distinctive world-scale gas market positions by accessing key pieces of infrastructure.

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

iii. To develop the world s leading low-carbon power generation and wholesale marketing and trading businesses.

In 2005, the segment was organized into four main activities: marketing and trading; natural gas liquids (NGL); new market development and LNG; and solar and renewables. On January 1, 2005, a small US operation, the Hobb fractionator, which supplies petrochemicals feedstock was transferred from Gas, Power and Renewables to the Olefins and Derivatives business reported within Other businesses & corporate. The 2004 and 2003 data below has been restated to reflect this transfer.

	Year ended December 31,		
	2005	**2004**	**2003**
		($ million)	
Sales and other operating revenues from continuing operations	25,557	23,859	22,568
Profit before interest and tax from continuing operations (a)	1,104	954	578
Total assets	28,441	17,257	10,859
Capital expenditure and acquisitions	235	524	439

(a) Includes profit after tax of equity-accounted entities.

The changes in sales and other operating revenues are explained in more detail below:

		Year ended December 31,		
		2005	**2004**	**2003**
Gas marketing sales	($ million)	15,222	13,532	12,929
Other sales (including NGL marketing)	($ million)	10,335	10,327	9,639
	($ million)	25,557	23,859	22,568
Gas marketing sales volumes	mmcf/d	5,096	5,244	5,881
Natural gas sales by Exploration and Production	mmcf/d	4,747	3,670	3,923

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.

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. We have strong upstream gas assets near the major markets, significant interests in gas pipelines and a series of integrated LNG positions in the Pacific and Atlantic basins. We are expanding our LNG business by accessing import terminals in Asia Pacific, North America and Europe. 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. 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 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 refining activities. We have significant NGLs processing and marketing business in North America.

In response to the growing demand for cleaner fuels, BP is investing to offer a real alternative for the generation of power with low-carbon emissions. During the year, we announced our plans to invest in a new business called BP Alternative Energy, which aims to extend significantly our capabilities in solar, wind power, hydrogen power and gas-fired power generation. Our solar and renewables activities include the development, production and marketing of solar panels, the development of wind farms on certain Group sites, generation of electricity from hydrogen while reducing CO_2 emissions through its capture and storage underground and gas-fired power generation projects.

Capital expenditure for 2005 was $235 million compared with $524 million in 2004 and $439 million in 2003. Capital expenditure excluding acquisitions for 2006 is planned to be around $530 million. The increase versus the 2005 level is primarily due to investment in the Alternative Energy business.

Our policy toward natural gas price risk is described in Item 11 Quantitative and Qualitative Disclosures About Market Risk on page 162.

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.

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 sales and other operating revenues for both IFRS and US GAAP.

(b) Over-the-counter (OTC) contracts

These contracts are typically in the form of forwards, swaps and options. OTC contracts are negotiated between two parties. They are not traded on an Exchange. These contracts can be used both as part of trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in sales and other operating revenues for both IFRS and US GAAP.

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. 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.

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. Amounts under these derivative financial instruments are settled at expiry, typically through netting agreements, to limit credit exposure and support liquidity.

(c) Spot and term contracts

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 IFRS and US GAAP, spot and term sales are included in sales and other operating revenues, when title passes. Similarly, spot and term purchases are included in purchases for IFRS and US GAAP.

Refer to Item 5 Operating and Financial Review Gas, Power and Renewables on page 90 and Item 11 Quantitative and Qualitative Disclosures About Market Risk on page 162 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. 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.

The scale of our gas and power businesses in North America grew over the period 2003 to 2005 because of a number of factors: (i) further establishing a position built on 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. 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. In addition to the marketing of BP gas, commodity derivative contracts are used actively in combination with assets and rights to store and transport gas to generate trading gains. 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. Over the period 2003 to 2005 this activity has declined in line with an overall reduction in the liquidity of the traded markets.

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

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 6.4 billion cubic feet per day (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 as well as West Coast and midcontinent regions. Our NGL processing capacity utilization in 2005 was 70%, despite disruptions to supply following the Gulf of Mexico hurricanes.

In the UK we operate one plant and we are a partner (33.33%) in a gas processing plant in Egypt with 1.1 bcf/d of gas processing capacity, which commenced gas processing in the fourth quarter of 2004.

The Group established a NGL 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 2003 to 2005, flattening out in 2005, as this new activity has become established.

New Market Development and LNG

Our new market development and LNG activities are focused on establishing international market positions to create maximum value from our upstream natural gas resources and on capturing complementary third-party LNG supply to complement our equity flows.

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.

We continue 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.

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 the UK, we, in co-operation with Sonatrach (the national oil company of Algeria), have access rights to the initial capacity of 0.45 bcf/d at the Isle of Grain terminal. The terminal was commissioned July 2005 with the first cargo sourced by BP. In Egypt, we signed an agreement with Egyptian Natural Gas Holding Company (EGAS) to purchase 1.45 billion cubic metres per year of LNG.

BP continues to progress options for new terminal development in the US. The most advanced is the proposed 1.2 billion cubic feet per day Crown Landing terminal to be located on the Delaware River in New Jersey. The Federal Energy Regulatory Commission (FERC) granted its approval for the siting, construction and operation of this project on June 15, 2006. BP continues to work with the state agencies in New Jersey to complete state permitting requirements and with the relevant federal, state

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and local authorities to put in place security plans for the facility and associated shipping activities. BP is also monitoring the progress of a proceeding filed by the State of New Jersey against the State of Delaware in the United States Supreme Court concerning New Jersey s jurisdiction over developments on its shores, including the project s loading jetty that extends into the Delaware River. The Court has agreed to hear the case. This new access point to market, together with existing capacity rights at Cove Point in Maryland, US, Bilbao, 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%) continues on track. Pre-commissioning cargo arrived in early June 2006 with first commissioning cargo delivery expected around the middle of 2006. These are 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% infrastructure and oil reserves/15.8% gas and condensate reserves).

Solar and Renewables

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

2005 has seen strong industry demand for photovoltaic products, although constrained by the global shortage of polysilicon. In 2005, BP Solar achieved sales of 105 megawatts (MW) an increase of 6% versus 2004 (2004 99 MW and 2003 71 MW).

BP Solar s main production facilities are located in Frederick, Maryland USA; Madrid, Spain; Sydney, Australia; and Bangalore, India. We are on track to expand our production capacity to 200MW by the end of 2006, with 140MW already built in support of our strategic growth plans announced in October 2004. The deployment of the additional capacity depends upon availability of polysilicon.

In China, BP Solar set up a joint venture with SunOasis to produce and market solar panels, aimed largely at bringing power to remote rural areas in China.

We are building expertise in wind energy and implementing wind projects on selected BP sites. In 2005, we completed construction of 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.

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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 manufacturing sites.

We operate a 776 MW gas-fired power generation facility and an associated LNG regasification facility at Bilbao, Spain (BP 25% share in each). The construction of K Power s (BP 35%) 1,074 MW gas fired combined cycle power project at Gwangyang, Korea has continued and start-up activities have commenced. Unit 1, having capacity of 535 MW, was commissioned in February 2005, whilst Unit 2, having the remaining capacity, is under testing and is expected to be commissioned in the third quarter of 2006. The 570 MW cogeneration plant at Texas City, Texas (50:50 joint venture with Cinergy Solutions, Inc.), which commenced operations in early 2004, supplies power and steam to BP s largest refining and petrochemicals complex. BP supplies natural gas to the Texas City plant and will use excess generation capacity to support power marketing and trading activities. Following the explosion and fire at the Texas City refinery on March 23, 2005, the cogeneration plant was shut down. It was restarted as part of the refinery s phased recommissioning in March 2006. 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.

In November 2005, we disposed of a 400 MW gas-fired power plant at Great Yarmouth in the UK (BP 100%).

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OTHER BUSINESSES AND CORPORATE

Other businesses and corporate comprises Finance, 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. In addition, for the periods shown, it included the portion of Olefins and Derivatives not included in the sale of Innovene to INEOS. This includes the equity-accounted investments in China (the SECCO petrochemicals complex) and Malaysia (Polyethylene Malaysia Sdn Bhd and Ethylene Malaysia Sdn Bhd). These investments were transferred to Refining and Marketing, effective January 1, 2006. On October 10, 2003 we completed the sale of our 50% interest in PT Kaltim Prima Coal to PT Bumi Resources.

	Year ended December 31,		
	2005	**2004**	**2003**
		($ million)	
Sales and other operating revenues for continuing operations	668	546	515
Profit (loss) before interest and tax from continuing operations (a)	(1,191)	164	(253)
Total assets	12,756	22,292	19,595
Capital expenditure and acquisitions	905	2,300	973

(a) Includes profit after interest and tax of equity-accounted entities.

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.

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.

Research, technology and engineering activities are carried out by each of the major business segments on the basis of a distributed programme coordinated by a technology coordination group. 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.

Across the Group, expenditure on research for 2005 was $502 million, compared with $439 million in 2004 and $349 million in 2003.

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 premiums with attendant transaction costs. This position is reviewed periodically.

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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 Angola, Norway, the UK, Russia, South America 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 68.

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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, technological feasibility 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 43 on page F-114 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. Twenty two proceedings involving governmental authorities are pending or known to be contemplated against BP and certain of its subsidiaries under federal, state or local environmental laws, each of which could result in monetary sanctions of $100,000 or more. 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 BP Products Texas City refinery as the unit was coming out of planned maintenance. Fifteen contractors died in the incident and many others were injured. In 2005, BP Products finalized, or is currently in process of negotiating, settlements in respect of fatalities and personal injury claims arising from the incident. The first trial of the unresolved claims is scheduled for September, 2006. The US Occupational Safety and Health Administration (OSHA), the US Chemical Safety and Hazard Investigation Board (CSB), the US Environmental Protection Agency and the Texas Commission on Environmental Quality, among other agencies, have conducted or are conducting investigations. At the conclusion of their investigation, OSHA issued citations alleging more than 300 violations of 13 different OSHA standards, and BP Products agreed not to contest the citations. BP Products settled that matter with OSHA on September 22, 2005, paying a $21.3 million penalty and undertaking a number of corrective actions designed to make the refinery safer. OSHA referred the matter to the US Department of Justice for criminal investigation, and the Department of Justice has opened an investigation. At the recommendation of the CSB, BP appointed an independent safety panel, the BP US Refineries Independent Safety Review Panel, under the chairmanship of James A Baker III. Other government legal actions are pending.

OSHA has also issued two OSHA citations to the BP Products Toledo, Ohio refinery on April 24, 2006. The penalty assessed for both citations was $2.4 million. The citations were based on two OSHA standards: the Process Safety Management Standard (29 CFR 1910.119) and the Hazardous (Classified) Locations Standard (29 CFR 1910.307). BP Products North America Inc. filed a notice of contest with OSHA on May 16, 2006 challenging the citations. This matter will be assigned to an administrative law

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judge with the Occupational Safety and Health Review Commission, which is an agency independent of OSHA. The procedures followed before the Review Commission are similar to those followed in federal judicial cases.

On March 2, 2006, a crude oil spill of an estimated 4,200 to 4,800 bbls occurred on a low pressure transit line in Alaska s North Slope Prudhoe Bay field operated by BP. The spill was reported to all the appropriate government agencies as soon as it was discovered and the portion of the line with the leak was shut down. The pipeline leak was caused by internal corrosion. The spill impacted approximately two acres of frozen tundra. Cleanup and rehabilitation of the area is complete and environmental damage to the tundra is expected to be minimal. US and State of Alaska investigations of the incident have been initiated. The Pipeline and Harzardous Materials Safety Administration (PHMSA), an agency of the US Department of Transportation, issued a Corrective Action Order to BP on March 15, 2006, regarding the three Prudhoe Bay oil transit lines and BP is in discussion with PHMSA on assuring compliance with the corrective actions outlined in the order.

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 91.

BP operates in over 100 countries worldwide. In all regions of the world, BP has processes designed to ensure compliance with applicable regulations. In addition, each individual in the Group is required to comply with BP health, safety and environment policies as embedded in the BP Code of Conduct. 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 EU, where approximately 65% 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

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. The Kyoto treaty came into force in 2005, committing the 156 participating countries to making emissions reductions and the EU Emissions Trading Scheme came into operation. However, Kyoto was only designed as a first step and policy makers are now discussing what new agreement might follow it in 2012 and how all significant countries can be involved. The issue was discussed by the G8 group of world leaders at their July summit and at the United Nations Climate Change meeting in Montreal in December. 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).

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 EU. 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.

In July 2003, final agreement was reached on a Directive establishing a scheme for greenhouse gas (GHG) emission allowance trading within the EU, and in January 2005, the scheme entered into force, capping the GHG 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 BP. We began the year with 30 participating operations but, following divestments in the fourth quarter, we ended 2005 with 18, which represent around a quarter of our reported global GHG emissions.

Since 1997, BP has been actively involved in policy debate. We also ran a global programme that reduced our operational GHG emissions by 10% between 1998 and 2001. We continue to 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 and products that we sell product emissions. Since 2001 we have been aiming to offset, through energy efficiency projects, half of the underlying operational GHG emission increases that result from our growing business. After four years, we estimate that emissions growth of some 10 million tonnes has been offset by around 5 million tonnes of sustainable reductions. With regard to our products, in 2005 we announced our plans to invest $8 billion over 10 years in a business called BP Alternative Energy. This new business aims to lead the market in low-carbon power generated from the sun, wind, natural gas and hydrogen.

Maritime Oil Spill Regulations

Within the United States, the Oil Pollution Act of 1990 (OPA 90) imposes 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. In addition to federal law (OPA 90) which imposes liability for oil spills on the owners and operators of the carrying vessel, some states implemented statutes also imposing liability on the shippers or owners of oil spilled from such vessels. Alaska, Washington, Oregon and California are among these states. The exposure of BP to such liability is mitigated by the vessels marine liability insurance which has a maximum limit of $1 billion for each accident or occurrence. 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. 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) which transports BP Alaskan crude oil from Valdez. NASSCO delivered two more in 2005, and delivery of the last is expected in 2006. At the end of 2005, the ATC fleet consisted of six tankers, all double-hulled.

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 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 (CLC) are covered by marine liability insurance having a maximum limit of $1 billion for each accident or occurrence. This insurance cover is provided by three mutual insurance associations (P&I Clubs), The United Kingdom

Steam Ship Assurance Association (Bermuda) Limited, The Britannia Steam Ship Insurance Association Limited and The Standard Steamship Owners Protection and Indemnity Association (Bermuda) Limited. With effect from February 20, 2006 two new complementary voluntary oil pollution compensation schemes were introduced by tanker owners, supported by their P&I Clubs, with the agreement of the International Oil Pollution Compensation Fund at the IMO. Pursuant to both of these schemes, tanker owners will voluntarily assume a greater liability for oil pollution compensation in the event of a spill of persistent oil than is provided for in CLC. The first scheme, The Small Tanker Owners Pollution Indemnification Agreement (STOPIA) provides for a minimum liability of 20 million Special Drawing Rights (around $29 million) for a ship at or below 29,548 gross tons, while the second scheme, The Tanker Owners Pollution Indemnification Agreement (TOPIA) provides for the tanker owner to take a 50% stake in the 2003 Supplementary Fund, i.e. an additional liability of up to 273.5 million Special Drawing Rights (around $406 million). Both STOPIA and TOPIA will only apply to tankers whose owners are party to these agreements and who have entered their ships with P&I Clubs in the International Group of P&I Clubs, thereby benefiting from those Clubs pooling and re-insurance arrangements. All of BP Shipping s managed and time chartered vessels will participate in STOPIA and TOPIA.

At the end of 2005, the international fleet we managed numbered 44 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 three new double-hulled oil tankers, four new very large liquefied petroleum gas carriers and four new liquefied natural gas carriers delivered between 2006 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 BP Shipping is accelerating the phase in of double-hulled vessels only by 2008; all vessels will continue to be vetted prior to each use as part of BP s effort 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, stricter fuel specifications and sulphur reductions; enhanced monitoring of major sources of specified pollutants; stringent air emission limits and 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, particulate matter, 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 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 each year by BP will have to meet a sulphur cap of 15 parts per million (ppm) and then 100% beginning January 2010. 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.

The Energy Policy Act of 2005 will also require several changes to the US fuels market with the following fuel provisions; elimination of the Federal Reformulated Gasoline (RFG) oxygen requirement in May 2006; establishment of a renewable fuels mandate 4 billion gallons in 2006, increasing to 7.5 billion in 2012; consolidation of the summertime RFG VOC standards for Region 1 and 2; provision to allow the Ozone Transport Commission states on the east coast to opt any area into RFG; and a provision to allow states to repeal the 1 psi Reid Vapor Pressure waiver for 10 percent ethanol blends.

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 requirements 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 2005, BP paid approximately $56 million in environmental and safety fines and penalties in the US, over 90% of which was paid in settlement of matters in Texas and California.

A plea agreement between BP Exploration (Alaska) Inc. (BPXA) and the US Justice Department, and the associated period of organizational probation, ended on January 31, 2005. Pursuant to this plea agreement BPXA developed and implemented a nationwide environmental management system consistent with the best environmental practices at Group facilities engaged in oil exploration, drilling and/or production in the US and its territories.

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. New regulations are expected that could require, for example, modifications of water intake structures and additional wastewater treatment systems at some facilities.

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 67 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). The estimated future cost of performing selected and proposed remedies in certain areas in the basin will

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likely exceed $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 other federal and state laws. NRD claims have been asserted by government trustees against a number of Group operations. This is a developing area of the law which could impact the cost of addressing 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 physical and chemical hazards and injury to employees; and the Emergency Planning and Community Right-to-Know Act which requires emergency planning and spill notification as well as public disclosure of chemical usage and emissions. In addition, the US Department of Transportation, through the Pipeline and Hazardous Materials Safety Administration, 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 training of a designated security person and the submission of plans for approval and inspection.

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.

See also Item 8 Financial Information Consolidated Statements and Other Financial Information Legal Proceedings on page 148.

European Union Regional Review

Within the EU, member states either apply the Directives of the European Commission directly or enact domestic provisions. By joint agreement, EU 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. 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 EU and consequently requires capital and revenue expenditure across BP sites. The European Commission has embarked upon a process of review which will result in recommendations for amendments to the IPPC Directive in 2006.

The EU 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 European commission has proposed a consolidation of framework and daughter directives together with the inclusion of additional requirements.

In 2005, The European Commission published its Thematic Strategy on Air Pollution (TSAP) and an accompanying proposal to consolidate existing ambient air quality legislation and introducing new controls on the concentration of fine particles (PM 2.5 particulate matter less than 2.5 microns diameter) in ambient air. The TSAP outlines EU-wide objectives to reduce the health and environmental impacts of air quality and a wide range of measures to be taken. These measures include: the ambient air quality proposal mentioned above; revisions to the National Emissions Ceilings Directive; new emission limits for light and heavy duty diesel vehicles; new controls on smaller combustion plant; and further control of 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 of 50 ppm and a 35% maximum aromatic content for gasoline were both agreed to apply from 2005. 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 started to take effect in 2006. 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 chief impact on BP is likely to arise from installation of flue gas desulphurization on ships and higher cost fuel. The overall impact is not expected to 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 2006. 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.

A European Commission proposal for new European chemical policy REACH (Registration, Evaluation and Authorization of Chemicals) was amended and voted separately at the end of 2005 by the European Council and Parliament. The remaining part of the adoption should present no significant obstacles and the new regulation is now expected to enter into force by mid-2007. All chemical substances manufactured or imported in the EU above 1 tonne per annum (about 30,000) will require a new pre-registration within the following 18 months, a registration within a 3 to 11- year time-phased period from adoption (actual date depends on volume bands or classification with high volumes and hazardous substances first). Only time-limited authorizations will be given to substances of high concern . A new European Chemical Agency will be established in Helsinki by mid-2008. Crude oil and natural gas are exempt. For BP, REACH will impact all refining petroleum products, petrochemicals, lubricants and other chemicals. An initial estimate suggests costs in the range $50,000-100,000 each for the internal preparation, pre-registration and registration of several hundred substances and preparations.

The European Commission adopted a Directive on Environmental Liability on April 21, 2004. The proposal seeks to implement a liability approach for damage to biodiversity and land, and for 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, injunctive relief and right of preventive action by 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.

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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.

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ORGANIZATIONAL STRUCTURE

The significant subsidiary undertakings of the Group at December 31, 2005 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 30 on page F-75, Item 18 Financial Statements Note 31 on page F-78 and Note 51 on page F-144 for information on significant joint ventures and associated undertakings of the Group.

Subsidiaries	%	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 Oil 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

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Subsidiaries	%	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	
BP Amoco Chemical Company	100	US	Exploration and production, gas,
BP Company North America	100	US	power and renewables, refining
BP Corporation North America	100	US	and marketing, pipelines and
BP Products North America	100	US	petrochemicals
BP West Coast Products	100	US	
The Standard Oil Company	100	US	
BP Capital Markets America	100	US	Finance

ITEM 4A UNRESOLVED STAFF COMMENTS

None.

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ITEM 5 OPERATING AND FINANCIAL REVIEW

GROUP OPERATING RESULTS

	Year ended December 31,		
	2005	2004	2003
	($ million except per share amounts)		
Sales and other operating revenues from continuing operations (a)	239,792	192,024	164,653
Profit from continuing operations (a)	22,133	17,884	12,681
Profit for the year	22,317	17,262	12,618
Profit for the year attributable to BP shareholders	22,026	17,075	12,448
Profit attributable to BP shareholders per ordinary share cents	104.25	78.24	56.14
Dividends paid per ordinary share cents	34.85	27.70	25.50

(a) Excludes Innovene which was treated as a discontinued operation in accordance with IFRS 5 Non-current Assets Held for Sale and Discontinued Operations . See Item 18 Financial Statements Note 5 on page F-35.

The business environment in 2005 was stronger than in 2004, with higher oil and gas realizations and higher refining and olefins margins but lower retail marketing margins.

Crude oil prices reached record highs in 2005 in nominal terms, driven by continued oil demand growth and low surplus oil production capacity. The dated Brent price averaged $54.48 per barrel, an increase of more than $16 per barrel above the $38.27 per barrel average seen in 2004, and varied between $38.21 and $67.33 per barrel. Hurricanes Katrina and Rita severely disrupted oil and gas production in the Gulf of Mexico for an extended period, but supply availability was maintained.

Natural gas prices in the US were also high during 2005 in the face of rising oil prices and hurricane-induced production losses. The Henry Hub First of the Month Index averaged $8.65 per mmbtu, up by around $2.50 per mmbtu compared with the 2004 average of $6.13 per mmbtu. High gas prices stimulated a fall in demand, especially in the industrial sector. UK gas prices were up strongly in 2005, averaging 40.71 pence per therm at the National Balancing Point, compared with a 2004 average of 24.39 pence per therm.

Refining margins also reached record highs in 2005, with the BP Global Indicator Margin averaging $8.60 per barrel. This reflected further oil demand growth and the loss of refining capacity as a result of the US hurricanes. The premium for light products above fuel oils remained exceptionally high, favouring upgraded refineries over less complex sites.

Retail margins weakened in 2005 as rising product prices and price volatility made their impact felt in a competitive marketplace.

The business environment in 2004 was affected by tight supplies in oil markets and by strong world economic growth.

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, driven by global oil demand growth and the physical disruption to US oil operations caused by hurricane Ivan. The price varied between $29.13 and $52.03 per barrel.

Natural gas prices in the US were stronger than in 2003. 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 in 2004, averaging 24.39 pence per therm at the National Balancing Point compared with a 2003 average of 20.28 pence per therm.

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Refining margins were high in 2004, despite weakening towards the end of the year. This reflected oil demand growth and higher refinery throughput levels. Retail margins weakened in 2004 compared with 2003, as rising product prices and price volatility made their impact in a competitive marketplace.

Business 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 higher than in 2002. 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 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 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.

Hydrocarbon production for subsidiaries decreased by 2.8% in 2005 reflecting a decrease of 3.9% for liquids and a decrease of 1.5% for natural gas. Increases in production in our new profit centres were more than offset by the effect of hurricanes, higher planned maintenance shutdowns and anticipated decline in our existing profit centres. Hydrocarbon production for equity-accounted entities increased by 7.8% reflecting an increase of 8.4% for liquids and an increase of 3.8% for natural gas. This increase primarily reflects increased production from TNK-BP.

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 102% 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.

The increase in sales and other operating revenues (before the elimination of sales between businesses) for 2005 includes approximately $67 billion from higher prices related to marketing and other sales (spot and term contracts, petrochemicals products, oil and gas realizations and other sales) and $1 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 $11 billion from lower volumes of marketing and other sales and a decrease of around $1 billion related to lower production volumes of subsidiaries.

The increase in sales and other operating revenues (before the elimination of sales between businesses) for 2004 compared with 2003 includes approximately $44 billion from higher prices related to marketing and other sales (spot and term contracts, petrochemicals products, oil and gas realizations and other sales) 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 of subsidiaries.

Profit attributable to BP shareholders for the year ended December 31, 2005 was $22,026 million, including inventory holding gains of $3,027 million. 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. Profit attributable to BP shareholders for the year ended December 31, 2004 was $17,075 million, including inventory holding gains of $1,643 million, and profit attributable to BP shareholders for the year ended December 31, 2003 was $12,448 million, including inventory holdings gains of $16 million.

The profit attributable to BP shareholders for the year ended December 31, 2005 includes profits from Innovene operations of $184 million, compared with losses of $622 million and $63 million in the years ended December 31, 2004 and December 31, 2003. The profit from Innovene for the year 2005 includes a loss on remeasurement to fair value of $591 million. Item 18 Financial Statements Note 5 on page F-35 provides further financial information for Innovene.

Profit attributable to BP shareholders for the year ended December 31, 2005:

includes net gains of $1,159 million on the sales of assets, primarily from our interest in the Ormen Lange field, and is after net fair value losses of $1,688 million on embedded derivatives, (these embedded derivatives are fair valued at each period end with the resulting gains or losses taken to the income statement), an impairment charge of $226 million in respect of fields in the Gulf of Mexico and a charge for impairment of $40 million relating to fields in the UK North Sea in Exploration and Production;

includes net gains of $177 million principally on the divestment of a number of regional retail networks in the US, and is after a charge of $1,200 million in respect of fatality and personal injury compensation claims associated with the incident at the Texas City refinery on March 23, 2005, a charge of $140 million relating to new, and revisions to existing, environmental and other provisions, an impairment charge of $93 million and a charge of $33 million for the impairment of an equity-accounted entity in Refining and Marketing;

includes net gains of $55 million primarily on the disposal of BP s interest in Interconnector and the disposal of an NGL plant in the US, and is after net fair value losses of $346 million on embedded derivatives and a credit of $6 million related to new, and revisions to existing, environmental and other provisions in the Gas, Power and Renewables segment; and

includes net gains on disposal of $38 million, and is after a net charge of $278 million related to new, and revisions to existing, environmental and other provisions and the reversal of environmental provisions no longer required, a charge of $134 million relating to the separation of the Olefins and Derivatives business and net fair value losses of $13 million on embedded derivatives in Other businesses and corporate.

Profit attributable to BP shareholders for the year ended December 31, 2004:

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 $108 million in respect of a gas processing plant in the USA and a field in the Gulf of Mexico Shelf, an impairment charge of $60 million in respect of the partner operated Temsah platform in Egypt following a blow-out, a net loss on disposal of $65 million, a charge of $35 million in respect of Alaskan tankers that are no longer required and, in addition, following the lapse of the sale agreement for oil and gas properties in Venezuela, $31 million of the previously booked impairment was reversed in Exploration and Production;

is after net losses on disposal of $261 million, a charge of $206 million related to new, and revisions to existing, environmental and other provisions, a charge of $195 million for the impairment of the petrochemicals facilities at Hull, UK and a charge of $32 million for restructuring, integration and rationalization in Refining and Marketing;

includes net gains on disposal of $56 million in the Gas, Power and Renewables segment; and

includes net gains on disposal of $1,164 million primarily related to the sale of our interests in PetroChina and Sinopec and a credit of $66 million primarily resulting from the reversal of vacant space provisions in the UK and US, and is after a charge of $283 million related to new, and revisions to existing, environmental and other provisions and a charge of $102 million relating to the separation of the Olefins and Derivatives business in Other businesses and corporate.

Profit attributable to BP shareholders for the year ended December 31, 2003:

includes net gains on disposal of $1,188 million, and is after impairment charges and asset writedowns of $1,013 million and restructuring charges of $117 million in Exploration and Production;

is after a $369 million charge in relation to new, and revisions to existing, environmental and other provisions, Veba integration costs of $287 million, net losses on disposal of $214 million and a credit of $10 million arising from the reversal of restructuring provisions in Refining and Marketing;

is after net losses on disposal of $6 million on Gas, Power & Renewables; and

includes a credit of $648 million relating to a US medical plan, net gains on disposal of $139 million 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, and is after a charge of $213 million in respect of new, and revisions to existing, environmental and other provisions and a charge of $110 million in respect of provisions for future rental payments on surplus property in Other businesses and corporate; and

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

Refer to Environmental Expenditure in this Item on page 91 for more information on environmental charges.

The primary additional factors contributing to the increase in profit attributable to BP shareholders for the year ended December 31, 2005 are higher liquids and gas realizations, higher refining margins and higher contributions from the operating business within the Gas, Power and Renewables segment; partially offset by lower retail marketing margins, higher costs (including the Thunder Horse incident, the Texas City refinery shutdown and planned restructuring actions) and significant volatility arising under IFRS fair value accounting.

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 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.

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 and refining margins. Accordingly, the results for the current and prior periods do not necessarily reflect trends, nor do they provide indicators of results for future periods.

Through non-US subsidiaries, BP conducts limited marketing, licensing and trading activities and technical studies in Iran and with Iranian counterparties including the National Iranian Oil Company (NIOC) and affiliated entities and has a small representative office in Iran. BP believes that these activities are immaterial to the Group. In addition, BP has interests in, and is the operator for, two fields outside of Iran in which NIOC and an affiliated entity have interests. However, BP does not seek to obtain from the government of Iran licenses or agreements for oil and gas projects in Iran and does not own or operate any refineries or chemicals plants in Iran.

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Employee numbers decreased from 103,700 at December 31, 2003 to 102,900 at December 31, 2004 to 96,200 at December 31, 2005. The decrease in 2005 resulted primarily from the sale of Innovene.

	Year ended December 31,		
Capital expenditure and acquisitions	**2005**	**2004**	**2003**
		($ million)	
Exploration and Production	10,149	9,654	9,398
Refining and Marketing	2,669	2,692	2,945
Gas, Power and Renewables	235	524	439
Other businesses and corporate	885	940	815
Capital expenditure	13,938	13,810	13,597
Acquisitions and asset exchanges	211	2,841	6,026
	14,149	16,651	19,623
Disposals	(11,200)	(4,961)	(6,356)
Net investment	2,949	11,690	13,267

Capital expenditure and acquisitions in 2005, 2004 and 2003 amounted to $14,149 million, $16,651 million and $19,623 million, respectively. There were no significant acquisitions in 2005. 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. Excluding acquisitions, capital expenditure for 2005 was $13,938 million compared with $13,810 million in 2004 and $13,597 million in 2003.

Finance Costs and Other Finance Expense

Finance costs comprises Group interest less amounts capitalized. Finance cost for continuing operations in 2005 was $616 million compared with $440 million in 2004 and $513 million in 2003. These amounts included a charge of $57 million arising from early redemption of finance leases in 2005 and a charge of $31 million in 2003 from early bond redemption. The charge for 2005 reflects higher interest costs partially offset by an increase in capitalized interest. 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.

Other finance expense includes net pension finance costs, the interest accretion on provisions and interest accretion on the deferred consideration for the acquisition of our investment in TNK-BP. Other finance expense for continuing operations in 2005 was $145 million compared with $340 million in 2004 and $532 million in 2003. The decrease in 2005 compared with 2004 primarily reflects a reduction in net pension finance costs. This is primarily due to a higher expected return on investment driven by a higher pension fund asset value at the start of 2005 compared with the start of 2004 while the expected long-term rate of return was similar. 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.

Taxation

The charge for corporate taxes for continuing operations in 2005 was $9,288 million, compared with $7,082 million in 2004 and $5,050 million in 2003. The effective rate was 30% in 2005, 28% in 2004 and 28% in 2003. The increase in the effective rate in 2005 is primarily due to a higher proportion of income in countries bearing higher tax rates, and other factors.

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Business Results

Profit before interest and taxation from continuing operations, which is before finance costs, other finance expense, taxation and minority interests, was $32,182 million in 2005, $25,746 million in 2004 and $18,776 million in 2003.

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Exploration and Production

		Year ended December 31,		
		2005	**2004**	**2003**
Sales and other operating revenues from continuing operations	($ million)	47,210	34,700	30,621
Profit before interest and tax from continuing operations (a)	($ million)	25,508	18,087	15,084
Results include:				
Exploration expense	($ million)	684	637	542
Of which: Exploration expenditure written off	($ million)	305	274	297
Key statistics:				
Average BP crude oil realizations (b)				
UK	($ per barrel)	51.22	36.11	28.30
USA	($ per barrel)	50.98	37.40	29.02
Rest of World	($ per barrel)	48.32	34.99	26.91
BP average	($ per barrel)	50.27	36.45	28.23
Average BP NGL realizations (b)				
UK	($ per barrel)	37.95	31.79	20.08
USA	($ per barrel)	31.94	25.67	18.39
Rest of World	($ per barrel)	35.11	27.76	22.31
BP average	($ per barrel)	33.23	26.75	19.26
Average BP liquids realizations (b)(c)				
UK	($ per barrel)	50.45	35.87	27.80
USA	($ per barrel)	47.83	35.41	27.23
Rest of World	($ per barrel)	47.56	34.51	26.60
BP average	($ per barrel)	48.51	35.39	27.25
Average BP US natural gas realizations (b)				
UK	($ per thousand cubic feet)	5.53	4.32	3.19
USA	($ per thousand cubic feet)	6.78	5.11	4.47
Rest of World	($ per thousand cubic feet)	3.46	2.74	2.47
BP average	($ per thousand cubic feet)	4.90	3.86	3.39
Average West Texas Intermediate oil price	($ per barrel)	56.58	41.49	31.06
Alaska North Slope US West Coast	($ per barrel)	53.55	38.96	29.59
Average Brent oil price	($ per barrel)	54.48	38.27	28.83
Average Henry Hub gas price (d)	($/mmbtu)	8.65	6.13	5.37
Total liquids production for subsidiaries (c)(e)	(mb/d)	1,423	1,480	1,615
Total liquids production for equity-accounted entities (c)(e)	(mb/d)	1,139	1,051	506
Natural gas production for subsidiaries (e)	(mmcf/d)	7,512	7,624	8,092
Natural gas production for equity-accounted entities (e)	(mmcf/d)	912	879	521
Total production for subsidiaries (e)(f)	(mboe/d)	2,718	2,795	3,011

Total production for equity-accounted entities (e)(f)	(mboe/d)	1,296	1,202	595

(a) Includes profit after interest and tax of equity-accounted entities.

(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.

(e) Net of royalties.

(f) 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.

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Sales and other operating revenues for 2005 were $47 billion compared with $35 billion in 2004 and $31 billion in 2003. The increase in 2005 primarily reflected an increase of around $13 billion related to higher liquids and gas realizations partly offset by a decrease of around $1 billion due to slightly lower volumes of subsidiaries. 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.

Profit before interest and tax for the year ended December 31, 2005 was $25,508 million, including inventory holding gains of $17 million and gains of $1,159 million on the sales of assets, primarily from our interest in the Ormen Lange field, and is after net fair value losses of $1,688 million on embedded derivatives (these embedded derivatives are fair valued at each period end with the resulting gains or losses taken to the income statement), an impairment charge of $226 million in respect of fields in the Gulf of Mexico, a charge for impairment of $40 million relating to fields in the UK North Sea and a charge of $265 million on the cancellation of an intra-Group gas supply contract.

Profit before interest and tax for the year ended December 31, 2004 was $18,087 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 $108 million in respect of a gas processing plant in the USA and a field in the Gulf of Mexico Shelf, an impairment charge of $60 million in respect of the partner operated Temsah platform in Egypt following a blow-out, a net loss on disposal of $65 million and a charge of $35 million in respect of Alaskan tankers that are no longer required. In addition, following the lapse of the sale agreement for oil and gas properties in Venezuela, $31 million of the previously booked impairment was reversed.

Profit before interest and tax for the year ended December 31, 2003 was $15,084 million, including inventory holding gains of $3 million and net gains on disposal of $1,188 million (primarily related to gains on the sale of the UK North Sea Forties field together with a package of shallow water assets in the Gulf of Mexico and Repsol s exercise of its option to acquire a further 20% interest in BP Trinidad & Tobago LLC and net losses resulting from the sale of various other upstream assets); and is after an impairment charge of $296 million for four fields in the Gulf of Mexico, following technical reassessment and re-evaluation of future investment options; impairment charges of $133 million and $49 million respectively for the Miller and Viscount fields in the UK North Sea as a result of a decision not to proceed with waterflood and gas import options and a reserve write-down respectively; an impairment charge of $105 million for the Yacheng field in China; an impairment charge of $108 million for the Kepadong field in Indonesia; and an impairment charge of $47 million for the Eugene Island/ West Cameron fields in the US as a result of reserve write-downs following completion of our routine full technical reviews. In addition, there were impairment charges of $217 million and $58 million for oil and gas properties in Venezuela and Canada respectively, based on fair value less costs to sell for transactions expected to complete in early 2004. Furthermore, there were restructuring charges of $117 million in respect of ongoing restructuring activities in the UK and North America.

In addition to the factors above, the primary reasons for the increase in profit before interest and tax for the year ended December 31, 2005 compared with the year ended December 31, 2004 are higher liquids and gas realizations contributing around $10,100 million and around $400 million from higher volumes (in areas not affected by hurricanes), offset partly by a decrease of around $900 million due to the hurricane impact on volumes, costs associated with hurricane repairs and Thunder Horse of around $200 million, and higher operating and revenue investment costs of around $1,700 million.

The primary additional reasons for the increase in profit before interest and tax 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, higher costs of around $650 million and increased equity-accounted interest and tax charges of around $1,000 million. The result of TNK-BP was included for a full-year in 2004 compared with four months in 2003.

Total production for the year 2005 was 2,718 mboe/d for subsidiaries and 1,296 mboe/d for equity-accounted entities compared with 2,795 mboe/d and 1,202 mboe/d respectively, a year ago. For subsidiaries, increases in production in our new profit centres were more than offset by the effect of the hurricanes, higher planned maintenance shutdowns and anticipated decline in our existing profit centres. For equity-accounted entities, this primarily reflects growth from TNK-BP.

Actual production for subsidiaries and equity-accounted entities in 2005, after adjusting for the impact of severe weather and the impact of higher prices on production sharing contracts, was 2,849 mboe/d and 1,296 mboe/d, respectively, compared with the range of between 2.85 and 2.9 mmboe/d for subsidiaries and between 1.25 and 1.3 mmboe/d for equity-accounted entities as previously indicated.

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 2003. For subsidiaries, the 7.2% decrease includes 95 mboe/d impact of divestments and for equity-accounted entities the increase of 102% includes an increase of 108 mboe/d from the TNK-BP share of Slavneft from January 2004.

Refining and Marketing

		Year ended December 31,		
		2005	**2004**	**2003**
Sales and other operating revenues from continuing operations	($ million)	213,465	170,749	143,441
Profit before interest and tax from continuing operations (a)	($ million)	6,442	6,544	3,235
Global Indicator Refining Margin (b)				
Northwest Europe	($/bbl)	5.47	4.28	2.62
US Gulf Coast	($/bbl)	11.40	7.15	4.71
Midwest	($/bbl)	8.19	5.08	4.54
US West Coast	($/bbl)	13.49	11.27	7.06
Singapore	($/bbl)	5.56	4.94	1.77
BP average	($/bbl)	8.60	6.31	4.08
Refining availability (c)	(%)	92.9	95.4	95.5
Refinery throughputs	(mb/d)	2,399	2,607	2,723

(a) Includes profit after interest and tax of equity-accounted entities.

(b) The Global Indicator Refining Margin (GIM) is the average of 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 taking account of downtime such as planned maintenance.

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The changes in sales and other operating revenues are explained in more detail below:

		Year ended December 31,		
		2005	2004	2003
Sale of crude oil through spot and term contracts	($ million)	36,992	21,989	22,224
Marketing, spot and term sales of refined products	($ million)	155,098	124,458	102,003
Other sales including non-oil and to other segments	($ million)	21,375	24,302	19,214
		213,465	170,749	143,441
Sale of crude oil through spot and term contracts	(mb/d)	2,464	2,312	2,387
Marketing, spot and term sales of refined products	(mb/d)	5,888	6,398	6,688

Sales and other operating revenues for 2005 was $213 billion compared with $171 billion in 2004 and $143 billion in 2003. The increase in 2005 compared with 2004 was principally due to an increase of around $31 billion in marketing, spot and term sales of refined products. This was due to higher prices of $39 billion and a positive foreign exchange impact due to a weaker dollar of $1 billion, partly offset by lower volumes of $9 billion. Additionally, sales of crude oil, spot and term contracts increased by $15 billion due to higher prices of $13 billion and higher volumes of $2 billion and other sales decreased by $3 billion, primarily due to lower volumes. The $28 billion increase in turnover in 2004 compared to 2003 was primarily due to due an increase in marketing, spot and term sales of refined products of around $23 billion. This was due to higher prices of $28 billion, a positive foreign exchange impact due to a weaker dollar of $8 billion and lower volumes of $13 billion. Additionally, sales of crude oil, spot and term contracts remained flat, reflecting higher prices of $1 billion offset by lower volumes of $1 billion. Other sales increased by around $5 billion, due to higher prices of $4 billion and higher volumes of $1 billion.

Profit before interest and tax for the year ended December 31, 2005 was $6,442 million, including inventory holding gains of $2,537 million and net gains of $177 million principally on the divestment of a number of regional retail networks in the US, and is after a charge of $1,200 million in respect of fatality and personal injury compensation claims associated with the incident at the Texas City refinery on March 23, 2005, a charge of $140 million relating to new, and revisions to existing, environmental and other provisions, an impairment charge of $93 million and a charge of $33 million for the impairment of an equity-accounted entity.

Profit before interest and tax for the year ended December 31, 2004 was $6,544 million, including inventory holding gains of $1,304 million, and is after net losses on disposal of $261 million (principally related to plant closures and exit from businesses, the disposal of our interest in the Singapore Refining Company Private Limited, the closure of the lubricants operation of the Coryton Refinery in the UK and the disposal of our European speciality intermediates businesses), a charge of $206 million related to new, and revisions to existing, environmental and other provisions, a charge of $195 million for the impairment of the petrochemicals facilities at Hull, UK and a charge of $32 million for restructuring, integration and rationalization.

Profit before interest and tax for the year ended December 31, 2003 was $3,235 million, including inventory holding gains of $43 million and is after a $369 million charge in relation to new, and revisions to existing, environmental and other provisions, Veba integration costs of $287 million (see below), net losses on disposal of $214 million (including the sale of retail assets, the Group s European oil speciality products business, refinery and retail interests in Germany and Central Europe and pipeline interests in the US) and a credit of $10 million arising from the reversal of restructuring provisions.

The primary additional reasons for the increase in profit before interest and tax for the year ended December 31, 2005, compared with the year ended December 31, 2004 were improved refining margins contributing approximately $2,000 million, offset by lower retail marketing margins reducing profits by approximately $720 million, a reduction of around $870 million due to the shutdown of the

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Texas City refinery, along with other storm related supply disruptions to a number of our US based businesses, an adverse impact of around $400 million due to fair value accounting for derivatives (see explanation below) and a reduction of around $430 million due to rationalization and efficiency programme charges, mainly across our marketing activities in Europe.

Where derivative instruments are used to manage certain economic exposures that cannot themselves be fair valued or accounted for as hedges, timing differences in relation to the recognition of gains and losses occur. These economic exposures primarily relate to inventories held in excess of normal operating requirements that are not designated as held for trading and fair valued, and forecast transactions to replenish inventory. Gains and losses on derivative commodity contracts are recognized immediately through the income statement whilst gains and losses on the related physical transaction are recognized when the commodity is sold.

Additionally, IFRS requires that inventory designated as held for trading is fair valued using period end spot prices whilst the related derivative instruments are valued using forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices resulting in quarterly timing differences.

The full year average GIM was higher than that for the full year 2004, and consistent with the increase in BP s actual realized refining margin. Retail marketing margins, despite the recovery in the fourth quarter, were significantly lower than those for the full year 2004, although partly offset by increases in our other marketing businesses. Our purchased energy costs and operating and investment costs were higher year-on-year due to refinery repair, manufacturing integrity costs and the initial charges for the rationalization and efficiency programmes mentioned above. Refining throughputs at 2,399 mb/d were lower than in 2004 due primarily to the impact of disposal of the Mersin and Singapore refineries in 2004 and reduced availability at the Texas City refinery due to the explosion at the isomerization unit in March 2005 and the refinery s complete shutdown in late September, like other refineries in the area, owing to hurricane Rita. Refining availability was 92.9% compared with 95.4% in 2004. Marketing volumes were around 1% lower than 2004 due primarily to the effects of price increases as a result of supply disruption in the USA.

The increase in profit before interest and tax for 2004 compared with 2003 is primarily due to stronger refining margins contributing approximately $2,900 million, offset by a decrease in marketing margins of approximately $200 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 2,607 mb/d were 4% lower than in 2003 due principally to the disposal of BP s interests in the Singapore Refining Company Private Limited, 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.

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.

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Gas, Power and Renewables

		Year ended December 31,		
		2005	2004	2003
Sales and other operating revenues from continuing operations	($ million)	25,557	23,859	22,568
Profit before interest and tax from continuing operations (a)	($ million)	1,104	954	578

(a) Includes profit after interest and tax of equity-accounted entities.

The changes in sales and other operating revenues are explained in more detail below:

		Year ended December 31,		
		2005	2004	2003
Gas marketing sales	($ million)	15,222	13,532	12,929
Other sales (including NGL marketing)	($ million)	10,335	10,327	9,639
	($ million)	25,557	23,859	22,568
Gas marketing sales volumes	mmcf/d	5,096	5,244	5,881
Natural gas sales by Exploration and Production	mmcf/d	4,747	3,670	3,923

Sales and other operating revenues for 2005 was $26 billion compared with $24 billion in 2004. Gas marketing sales increased by $1.7 billion as price increases of $2.1 billion more than offset lower volumes of $0.4 billion. Other sales (including NGL marketing) remained flat reflecting $0.1 billion related to higher prices and $0.1 billion to lower volumes. Sales and other operating revenues for 2004 was $24 billion compared with $23 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, and other sales (including NGL marketing) increased by around $0.7 billion of which $2.1 billion related to higher prices and $1.4 billion to lower volumes. Gas marketing sales volumes declined in 2004 and 2005 due to production and customer portfolio changes and, in 2005, production loss caused by hurricanes in the Gulf of Mexico.

Profit before interest and tax for the year ended December 31, 2005 was $1,104 million, including inventory holding gains of $95 million, compensation of $265 million received on the cancellation of an intra-Group gas supply contract and net gains of $55 million primarily on the disposal of BP s interest in Interconnector, a power plant in the UK and an NGL plant in the US, and is after net fair value losses of $346 million on embedded derivatives and a credit of $6 million related to new, and revisions to existing, environmental and other provisions.

Profit before interest and tax for the year ended December 31, 2004 was $954 million, including inventory holding gains of $39 million and a net gain on disposal of $56 million.

Profit before interest and tax for the year ended December 31, 2003 was $578 million, including inventory holding gains of $6 million and is after a net loss on disposal of $6 million resulting from several small transactions.

The additional factors contributing to the increase in profit before interest and tax for the year ended December 31, 2005, compared with the equivalent period in 2004 are higher contributions from the operating businesses of around $170 million.

In addition to the factors above, the principal additional factors contributing to the increase in profit before interest and tax 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.

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Other Businesses and Corporate

		Year ended December 31,		
		2005	2004	2003
Sales and other operating revenues from continuing operations	($ million)	668	546	515
Profit (loss) before interest and tax from continuing operations (a)(b)	($ million)	(1,191)	164	(253)

(a) Includes profit after interest and tax of equity-accounted entities.

(b) Includes the portion of Olefins and Derivatives not included in the sale of Innovene to INEOS. This includes the equity-accounted investments in China and Malaysia that were part of the Olefins and Derivatives business. These investments have been transferred to Refining and Marketing effective January 1, 2006.

Other businesses and corporate comprises Finance, 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. In addition, as noted above, it included the portion of Olefins and Derivatives not included in the sale of Innovene to INEOS. On October 10, 2003 we completed the sale of our 50% interest in PT Kaltrim Prima Coal to PT Bumi Resources.

The loss before interest and tax for the year ended December 31, 2005 was $1,191 million, including a net gain on disposal of $38 million, and is after inventory holding losses of $5 million, a net charge of $278 million relating to new, and revisions to existing, environmental and other provisions and the reversal of environmental provisions no longer required, a charge of $134 million in respect of the separation of the Olefins and Derivatives business and net fair value losses of $13 million on embedded derivatives.

The profit before interest and tax for the year ended December 31, 2004 was $164 million, including inventory holding gains of $8 million, net gains on disposals of $1,164 million primarily related to the sale of our interests in PetroChina and Sinopec and a credit of $66 million primarily resulting from the reversal of vacant space provisions in the UK and the US, and is after a charge of $283 million related to new, and revisions to existing, environmental and other provisions, and a charge of $102 million relating to the separation of the Olefins and the Derivatives business.

The loss before interest and tax for the year ended December 31, 2003 was $253 million including a credit of $648 million relating to a US medical plan, net gains on disposal of $139 million (primarily comprising gains on the sale of our interest in PT Kaltim Prima Coal, an Indonisian coal mining company, and gains and losses on other smaller transactions) 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 and is after inventory holding losses of $1 million, a charge of $213 million in respect of new, and revisions to existing, environmental and other provisions and a charge of $110 million in respect of provisions for future rental payments on surplus property.

Environmental Expenditure

	Year ended December 31,		
	2005	2004	2003
		($ million)	
Operating expenditure	494	526	498
Clean-ups	43	25	45
Capital expenditure	789	524	546
Additions to environmental remediation provision	565	587	599

Additions to decommissioning provision	1,023	286	1,159

Operating and capital expenditure on the prevention, control, abatement or elimination of air, water and solid waste pollution is often not incurred as a separately 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 expenditures for 2005 were broadly in line with 2004. The increase in capital expenditure is largely related to clean fuels investment. Similar levels of operating and 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 2005 includes $512 million resulting from a reassessment of existing site obligations and $53 million in respect of provisions for new sites.

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

The extent and cost of future remediation programmes are inherently difficult to estimate. They depend on the scale of any possible contamination, the timing and extent of corrective actions and also the Group s share of 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 engaged in similar industries, or that our competitive position will be adversely affected as a result.

In addition, we make provisions on installation of our oil- and gas-producing assets and related pipelines to meet the cost of eventual decommissioning. 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. The level of increase in the decommissioning provision varies with the number of new fields coming on stream in a particular year and the outcome of the periodic reviews.

Provisions for environmental remediation and decommissioning are usually set up on a discounted basis, as required by IAS 37 Provisions, Contingent Liabilities and Contingent Assets .

Further details of decommissioning and environmental provisions appear in Item 18 Financial Statements Note 43 on page F-114. See also Item 4 Information on the Company Environmental Protection on page 68.

Insurance

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

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LIQUIDITY AND CAPITAL RESOURCES

Cash Flow

	Year ended December 31,		
	2005	2004	2003
		($ million)	
Net cash provided by operating activities of continuing operations	25,751	24,047	15,955
Net cash provided by (used in) operating activities of Innovene operations	970	(669)	348
Net cash provided by operating activities	26,721	23,378	16,303
Net cash used in investing activities	(1,729)	(11,331)	(9,281)
Net cash used in financing activities	(23,303)	(12,835)	(6,803)
Currency translation differences relating to cash and cash equivalents	(88)	91	121
Increase (decrease) in cash and cash equivalents	1,601	(697)	340
Cash and cash equivalents at beginning of year	1,359	2,056	1,716
Cash and cash equivalents at end of year	2,960	1,359	2,056

Net cash provided by operating activities for the year ended December 31, 2005 was $26,721 million compared with $23,378 million for the equivalent period of 2004, reflecting an increase in profit before taxation from continuing operations of $6,455 million, an increase in net cash provided by operating activities of Innovene of $1,639 million, a lower charge for provisions, less payments of $1,210 million and an increase in dividends received from jointly controlled entities and associates of $634 million. This was partially offset by an increase in income taxes paid of $2,640, an increase of $1,320 million in working capital requirements, an increase in earnings from jointly controlled entities and associates of $1,263 million, a higher net credit for impairment and gain/ loss on sale of businesses and fixed assets of $775 million, an increase in interest paid of $429 million and an increase in the net operating charge for pensions and other post-retirement benefits, less contributions of $351 million.

Net cash provided by operating activities for the year ended December 31, 2004 was $23,378 million compared with $16,303 million in 2003. This reflects an increase in profit before taxation from continuing operations of $7,235 million, the absence of discretionary funding for the Group s pension plans of $2,533, an increase in dividends received from jointly controlled entities and associates of $1,651 million (primarily due to the dividend from TNK-BP) and an increase in depreciation, depletion and amortization of $453 million. This was partially offset by an increase in income taxes paid of $1,584, an increase in earnings from jointly controlled entities and associates of $1,066 million, an increase of $1,054 million in working capital requirements and a decrease of $1,017 million in net cash provided by Innovene operations.

Net cash used in investing activities was $1,729 million compared with $11,331 million and $9,281 million for the equivalent periods of 2004 and 2003. The reduction in 2005 reflects an increase in disposal proceeds of $6,239 million, primarily from the sale of Innovene, and a decrease in spending on acquisitions of $2,693 million. The increase in 2004 compared with 2003 reflects a reduction in disposal proceeds of $1,395 million, increased acquisition spending of $191 million and increased capital expenditure of $401 million.

Net cash used in financing activities was $23,303 million compared with $12,835 million in 2004 and $6,803 million in 2003. The higher outflow in 2005 reflects an increase in the net repurchase of ordinary share capital of $4,107, higher repayments of long-term financing of $2,616 million, a net decrease of $1,433 million in short-term debt, and increases in equity dividends paid to BP shareholders of $1,318 million and to minority interest of $794 million. The higher outflow in 2004 compared with 2003 reflects an increase in the net repurchase of ordinary share capital of $5,319 million, lower proceeds from long-term financing of $1,647 million and an increase in equity dividends paid to BP shareholders of $387 million, partially offset by lower repayments of long-term financing of $1,356 million.

The Group has had significant levels of capital investment for many years. Capital investment, excluding acquisitions, was $13.9 billion in 2005, $13.8 billion in 2004 and $13.6 billion in 2003. 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. The Group s level of net debt, that is debt less cash and cash equivalents, was $20.3 billion at the end of 2003, $21.7 billion at the end of 2004 and was $16.2 billion at the end of 2005. The lower level of debt at the end of 2005 reflects the receipt of the Innovene disposal proceeds in December 2005.

Over the period 2003 to 2005 our cash inflows and outflows were balanced, with sources and uses both totalling $89 billion. During that period, the price of Brent has averaged $40.52/bbl. The following table summarizes the three year sources and uses of cash:

Sources		**Uses**	
	($ billion)		**($ billion)**
Net cash provided by operating activities	66	Capital expenditure	40
Divestments	23	Acquisitions	5
		Net repurchase of shares	20
		Dividends to BP shareholders	19
		Dividends to Minority Interest	1
		Movement in net debt	4
	89		89

Significant acquisitions made for cash were more than offset by divestitures. Net investment over the same period has averaged $7.3 billion per year. Dividends to BP shareholders, which grew on average by 14.3% per year in dollar terms, used $19 billion. Net repurchase of shares was $20 billion, which includes $21 billion in respect of our share buyback programme less proceeds from share issues. Finally, cash was used to strengthen the financial condition of certain of our pension funds. In the last three years, $3.7 billion has been contributed to funded pensions plans.

Trend Information

We expect to grow cash flows underpinned by the following:

We expect to grow production in a $40/bbl price environment.

We aim to control cost increases below inflation.

We plan to maintain capital expenditure at around $15 billion in 2006 and grow it at about $0.5 billion a year to 2008.

We expect to continue to high grade our portfolio and expect divestments to be an ongoing rate of around $3 billion a year.

As noted above, we expect capital expenditure, excluding acquisitions, to be around $15 billion in 2006; the exact level will depend on a number of things including sector-specific cost escalation above levels we have seen so far, time critical and material one-off investment opportunities which further our strategy and any acquisition opportunities that may arise. At present, we do not expect any of these things to affect our capital expenditure. Refer to Item 4 for further information.

The UK Government s announced increase in the North Sea supplemental tax rate will, when enacted, result in higher tax charges. This increase will have two effects; first to create a one-time deferred tax charge of around $600 million and second to increase the ongoing Group effective tax rate by 2%. The full year aggregate effective tax rate is expected to be around 39%.

Total production for 2006 is estimated at an average of between 2.8 and 2.85 mmboe/d for subsidiaries and between 1.3 and 1.35 mmboe/d for equity-accounted entities; these estimates are based the Group s asset portfolio at January 1, 2006, anticipated start-ups in 2006 and Brent at $40/bbl, before any 2006 disposal effects, and before any effects of prices above $40/bbl on volumes in Production Sharing Agreements. The daily production of the Gulf of Mexico Shelf assets, whose sale was announced in April 2006, is estimated at 27 mboe.

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 growth in our equity-accounted joint venture, TNK-BP, is expected to moderate to between 2% and 3% over the period 2005 to 2010.

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

- the prevailing circumstances of the Group;
- the future investment patterns and sustainability of the Group;
- the future trading environment. It does seem that oil prices may have a support level of at least $40/bbl in the medium term. We continue to use our planning assumption of $25/bbl for testing the downside in the balance between investment and total distributions to shareholders.

We remain committed to returning the excess of net cash provided by operating activities less net cash used in investing activities to our investors where this is in excess of investment and dividend needs.

We plan to continue our programme of share buybacks, subject to market conditions and constraints. Since the inception of the share repurchase programme in 2000 until the end of 2005 we have repurchased some 2,662 million shares at a cost of $25.2 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 9%. During the first quarter of 2006, we bought back 349 million shares, at a cost of $4 billion.

Our financial framework includes a gearing band of 20-30% which is intended to provide an efficient capital structure and the appropriate level of financial flexibility. Our aim is to return gearing, which was 17% at December 31, 2005, to the lower half of the band.

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 and 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 12 and Item 3 Key Information Risk Factors on pages 10 and 11 which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements. The Company provides no commitment to update the forward-looking statements or to publish financial projections 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, 2005 amounted to $19,162 million (2004 $23,091 million) of which $8,932 million (2004 $10,184 million) was short term.

Net debt was $16,202 million at the end of 2005, a decrease of $5,530 million compared with 2004. The ratio of net debt to net debt plus equity was 17% at the end of 2005 and 22% at the end of 2004. The ratio of 17% at December 31, 2005 reflects stronger cash flows both from underlying operations and the sale of Innovene.

The maturity profile and fixed/floating rate characteristics of the Group s debt are described in Item 18 Financial Statements Notes 38 and 41 on pages F-97 and F-107, 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, 2006, the amount drawn down against the DIP was $6,988 million.

Commercial paper markets in the USA and Europe are a primary source of liquidity for the Group. At December 31, 2005 the outstanding commercial paper amounted to $1,911 million (2004 $4,180 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 associates. At December 31, 2005 the Group s share of third party borrowings of joint ventures and associates was $3,266 million (2004 $2,821 million) and $970 million (2004 $1,048 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, 2005 are summarized below. Some guarantees outstanding are in respect of borrowings of joint ventures and associates noted above.

	Guarantees expiring by period						
	Total	**2006**	**2007**	**2008**	**2009**	**2010**	**2011 and thereafter**
				($ million)			
Guarantees issued in respect of:							
Borrowings of joint ventures and associates	1,228	69	217	119	121	104	598
Liabilities of other third parties	736	161	470	28	25	5	47

At December 31, 2005 contracts had been placed for authorized future capital expenditure estimated at $7,596 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, 2005, the Group

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had available undrawn committed borrowing facilities of $4,500 million ($4,500 million at December 31, 2004).

Contractual Commitments

The following table summarizes the Group s principal contractual obligations at December 31, 2005. Further information on borrowings and finance leases is given in Item 18 Financial Statements Note 41 on page F-107 and further information on operating leases is given in Item 18 Financial Statements Note 18 on page F-58.

Expected payments by period under contractual obligations and commercial commitments	Payments due by period						
	Total	2006	2007	2008	2009	2010	2011 and thereafter
	($ million)						
Borrowings (a)	18,381	5,418	3,274	2,317	2,258	572	4,542
Finance lease obligations	1,236	78	78	80	80	82	838
Operating leases	10,609	1,569	1,473	1,069	1,009	953	4,536
Decommissioning liabilities	9,511	181	212	188	175	163	8,592
Environmental liabilities	2,501	499	367	332	314	313	676
Pensions and other postretirement benefits (b)	21,438	1,357	1,345	1,343	870	870	15,653
Purchase obligations (c)	126,725	87,696	11,473	5,081	3,694	2,871	15,910

(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 and the expected future payments for postretirement benefits.

(c) 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 2006 include purchase commitments existing at December 31, 2005 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 162.

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

Purchase obligations payments due by period	Payments due by period						
	Total	2006	2007	2008	2009	2010	2011 and thereafter
	($ million)						
Crude oil and oil products	45,688	39,767	1,663	754	732	707	2,065
Natural gas	41,823	25,541	3,783	2,329	1,622	1,240	7,308
Chemicals and other refinery feedstocks	11,376	5,043	1,348	669	404	404	3,508
Utilities	21,415	15,586	3,779	611	402	104	933
Transportation	3,184	1,036	496	338	260	208	846

Use of facilities and services	3,239	723	404	380	274	208	1,250
Total	126,725	87,696	11,473	5,081	3,694	2,871	15,910

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The following table summarizes the Group s capital expenditure commitments at December 31, 2005 and the proportion of that expenditure for which contracts have been placed. The Group expects its total capital expenditure excluding acquisitions to be around $15 billion in 2006 and to increase by about $0.5 billion a year through 2008.

Capital expenditure commitments including amounts for which contracts have been placed	Total	2006	2007	2008	2009	2010	2011 and thereafter
				($ million)			
Committed on major projects	19,254	8,498	4,060	2,179	1,392	879	2,246
Amounts for which contracts have been placed	7,596	4,767	1,551	696	428	138	16

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, 2005, the Group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,500 million expiring in 2006 (2004 $4,500 million expiring in 2005 and 2003 $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 these 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.

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OUTLOOK

World economic growth appears robust. The US appears to have rebounded in the first quarter, Europe continues to show promise of an acceleration of growth, and Asia and Latin America are growing at or around trend. The near-term global outlook is for sustained growth.

Crude oil prices averaged $61.79 per barrel (Dated Brent) in the first quarter of 2006, an increase of nearly $5 per barrel from the fourth quarter 2005 and more than $14 per barrel above the same period last year. Prices rebounded in face of a disruption of Nigerian supplies and heightened geopolitical concerns. Ample inventories and increased OPEC production capacity have failed to stem the increase. Oil prices are expected to remain strong.

US natural gas prices averaged $9.01/mmbtu (Henry Hub first of month index) in the first quarter, nearly $4/mmbtu below the fourth quarter of last year. Demand weakness has more than offset supply lost following last year s hurricanes, resulting in a substantial gain in inventories relative to seasonal norms. Mild winter weather has contributed to demand softness. As a result, prices have fallen below parity with residual fuel oil. US gas prices are expected to track broadly with oil prices but are vulnerable to further relative declines if inventories remain well above average.

UK gas prices (National Balancing Point day-ahead) in the first quarter averaged 70 pence per therm, up from 65.3 pence per therm in the fourth quarter and 32 pence per therm above the same period last year. Cold weather and the closure of the Rough storage facility in mid-March prompted a brief price spike above 150 pence per therm amid concerns about physical supply availability. Prompt prices have recently fallen below 30 pence per therm.

Global average refining margins softened to $6.28/bbl in the first quarter compared with $7.60/bbl in the fourth quarter of 2005. US refinery operations are still recovering from last autumn s hurricanes and a heavy maintenance programme has extended into the second quarter. During the second quarter, refining margins have risen in anticipation of the US driving season and the switch from MTBE to ethanol-blended reformulated gasoline and are likely to remain underpinned in the near term.

During the first quarter, an initial improvement in retail margins reversed resulting in an overall decline during the quarter. This was against a backdrop of increasing product prices, particularly in February and March. A further rise in wholesale gasoline and crude prices is evident during the second quarter and marketing margins are expected to remain volatile.

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CRITICAL ACCOUNTING POLICIES AND NEW ACCOUNTING STANDARDS

Adoption of International Financial Reporting Standards

For all periods up to and including the year ended December 31, 2004, BP prepared its financial statements in accordance with UK GAAP. BP, together with all other EU companies listed on an EU stock exchange, was required to prepare consolidated financial statements in accordance with IFRS as adopted by the EU with effect from January 1, 2005. The Annual Report and Accounts for the year ended December 31, 2005 comprises BP s first consolidated financial statements prepared under International Financial Reporting Standards.

In preparing these financial statements, the Group has complied with all International Financial Reporting Standards applicable for periods beginning on or after January 1, 2005. In addition, BP has also decided to adopt early IFRS 6 Exploration for and Evaluation of Mineral Resources , the amendment to IAS 19 Amendment to International Accounting Standard IAS 19 Employee Benefits: Actuarial Gains and Losses, Group Plans and Disclosures , the amendment to IAS 39 Amendment to International Accounting Standard IAS 39 Financial Instruments: Recognition and Measurement: Cash Flow Hedge Accounting of Forecast Intragroup Transactions and IFRIC 4 Determining whether an Arrangement contains a Lease . The EU has adopted all standards and interpretations adopted by BP for its 2005 reporting.

The general principle that should be applied on first-time adoption of IFRS is that standards in force at the first reporting date (for BP, December 31, 2005) should be applied retrospectively. However, IFRS 1 First-time Adoption of International Financial Reporting Standards (IFRS 1) contains a number of exemptions that companies are permitted to apply. BP has taken the following exemptions:

Comparative information on financial instruments is prepared in accordance with UK GAAP and the Group has adopted IAS 32 Financial Instruments: Disclosure and Presentation (IAS 32) and IAS 39 Financial Instruments: Recognition and Measurement (IAS 39) from January 1, 2005.

IFRS 3 Business Combinations has not been applied to acquisitions of subsidiaries or of interests in jointly controlled entities and associates that occurred before January 1, 2003.

Cumulative currency translation differences for all foreign operations are deemed to be zero at January 1, 2003.

The Group has recognized all cumulative actuarial gains and losses on pensions and other postretirement benefits as at January 1, 2003 directly in equity.

IFRS 2 Share-based Payment has been applied retrospectively to all share-based payments that had not vested before January 1, 2003.

As indicated above, BP adopted IAS 32 and IAS 39 with effect from January 1, 2005 and, as permitted under IFRS 1, the Group has not restated comparative information. Had IAS 32 and IAS 39 been applied from January 1, 2003, the following adjustments would have been necessary in the financial statements for the years ended December 31, 2004 and 2003:

All derivatives, including embedded derivatives, would have been brought on to the balance sheet at fair value.

Available-for-sale investments would have been carried at fair value rather than at cost.

The principal differences for the Group between reporting on the basis of UK GAAP and IFRS are as follows:

Ceasing to amortize goodwill.

Setting up deferred taxation on acquisitions; inventory valuation differences; and unremitted earnings of subsidiaries, jointly controlled entities and associates.

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Expensing a greater proportion of major maintenance costs.

No longer recognizing dividends proposed but not declared as a liability at the balance sheet date.

Recognizing an expense for the fair value of employee share option schemes.

Recording asset swaps on the basis of fair value.

Recognizing changes in the fair value of embedded derivatives in the income statement.

Further information regarding the impact of adopting IFRS is shown in Item 18 Financial Statements Note 3 on page F-30 and Note 52 on page F-145.

The new accounting policies adopted by the Group are summarized in Item 18 Financial Statements Note 1 on page F-12.

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 Financial Statements.

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, the recoverability of asset carrying values, deferred taxation, contingent liabilities, provisions and liabilities, pensions and other postretirement benefits.

Oil and Natural Gas Accounting

Accounting for oil and gas exploration and development activity is subject to special accounting rules that are unique to the oil and gas industry. In the absence of an IFRS dealing specifically with oil and gas accounting (IFRS 6 Exploration for and Evaluation of Mineral Resources only addresses limited areas), BP continues to have regard to the accounting guidance for oil and gas companies contained in the UK Statement of Recommended Practice, Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities (UK SORP).

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

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

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

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

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

Once a project is sanctioned for development, the carrying values of licence and property acquisition costs and exploration and appraisal costs are transferred to production assets within property, plant and equipment. Field development costs subject to depreciation are expenditures incurred to date, together with sanctioned future development expenditure approved by the Group.

The capitalized exploration and development costs for proved oil and gas properties (which include the costs of drilling unsuccessful wells) are amortized on the basis of oil-equivalent barrels that are produced in a period as a percentage of the estimated proved reserves.

The estimated proved reserves used in these unit-of-production calculations vary with the nature of the capitalized expenditure. The reserves used in the calculation of the unit-of-production amortization are as follows:

Proved developed reserves for producing wells.

Total proved reserves for development costs.

Total proved reserves for licence and property acquisition costs.

Total proved reserves for future decommissioning costs.

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

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

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

Oil and Natural Gas Reserves

BP estimates its proved reserves based on guidance contained in the UK SORP. This differs from the basis for determining reserve required by the US Securities and Exchange Commission. In estimating its reserves under UK SORP, BP uses long-term planning prices; these are the long term price assumptions on which the Group makes decisions to invest in the development of a field. Using planning prices for estimating proved reserves removes the impact of the volatility inherent in using year-end spot prices on our reserve base and on cash flow expectations over the long term. The Group s planning prices for estimating reserves through the end of 2005 were $25/bbl for oil and

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$4.00/mmbtu for natural gas. Applying higher year-end prices to reserve estimates and assuming they apply to the end-of-field life has the effect of increasing proved reserves associated with concessions (tax and royalty arrangements) for which additional development opportunities become economic at higher prices or where higher prices make it more economic to extend the life of a field. On the other hand, applying higher year-end prices to reserves in fields subject to PSAs has the effect of decreasing proved reserves from those fields because higher prices result in lower volume entitlements. We believe that our long-term planning price assumptions provide the most appropriate basis for estimating oil and gas reserves and we will continue to use this basis for our UK reporting.

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

The Company s proved reserves estimates for the year ended December 31, 2005 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 2005 year-end marker prices used were Brent $58.21/bbl and Henry Hub $9.52/mmbtu. The other 2005 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 and S-5.

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

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

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

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

Recoverability of Asset Carrying Values

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

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cash generating unit and associated goodwill with the recoverable amount of the asset, that is, the higher of net realizable value and value in use. Value in use is usually determined on the basis of discounted estimated future net cash flows.

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

For oil and natural gas properties, the expected future cash flows are estimated based on the Group s plans to continue to produce and develop proved and associated risk-adjusted probable and possible reserves. Expected future cash flows from the sale or production of reserves are calculated based on the Group s best estimate of future oil and gas prices. Prices for oil and natural gas used for future cash flow calculations are assumed to decline from existing levels in equal steps during the next three years to the long-term planning assumptions as at December 31, 2005 ($25 per barrel and $4.00 per mmbtu for Brent and Henry Hub respectively). Previously, the long-term planning assumptions were a Brent oil price of $20 per barrel and a Henry Hub gas price of $3.50 per mmbtu. These long-term planning assumptions are subject to periodic review and modification. The estimated future level of production is based on assumptions about future commodity prices, lifting and development costs, field decline rates, market demand and supply, economic regulatory climates and other factors.

Charges for impairment are recognized in the Group s results from time to time as a result of, among other factors, adverse changes in the recoverable reserves from oil and natural gas fields, low plant utilization or reduced profitability. If there are low oil prices or natural gas prices or refining margins or marketing margins over an extended period, the Group may need to recognize significant impairment charges.

Irrespective of whether there is any indication of impairment, BP is required to test for impairment any goodwill acquired in a business combination. The Group carries goodwill of approximately $10.4 billion on its balance sheet, principally relating to the Atlantic Richfield and Burmah Castrol acquisitions. In testing goodwill for impairment, the Group uses a similar approach to that described above. The cash-generating units for impairment testing in this case are one level below business segments. As noted above, if there are low oil prices or natural gas prices or refining margins or marketing margins for an extended period, the Group may need to recognize significant goodwill impairment charges.

Deferred Taxation

The Group has approximately $5 billion of carry forward tax losses in the UK and Germany, which would be available to offset against future taxable income. Carry forward tax losses in other taxing jurisdictions have not been recognized as deferred tax assets, and are unlikely to have a significant effect on the Group s tax rate in future years.

Provisions and Liabilities

The Group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest asset removal obligations facing BP relate to the removal and disposal of oil and natural gas platforms and pipelines around the world. The estimated discounted costs of dismantling and removing these facilities are accrued on the installation of those facilities, reflecting our legal obligations at that time. A corresponding asset of an amount equivalent to the provision is also created within property, plant and equipment. This asset is depreciated over the expected life of the production facility or pipeline. Most of these removal events are many years in the future and the precise requirements that will have to be met when the removal event actually occurs are uncertain. Asset removal technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty. Changes in the expected future costs are reflected in both the provision and tangible asset.

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

The timing and amount of future expenditures are reviewed annually, together with the interest rate to be used in discounting the cash flows. The interest rate used to determine the balance sheet obligation at the end of 2005 was 2.0%, unchanged from the end of 2004. The interest rate represents the real rate (i.e. adjusted for inflation) on long-dated government bonds.

Other provisions and liabilities are recognized in the period when it becomes probable that there will be a future outflow of funds resulting from past operations or events that can be reasonably estimated. The timing of recognition requires the application of judgement to existing facts and circumstances, which can be subject to change. Since the actual cash outflows can take place many years in the future, the carrying amounts of provisions and liabilities are reviewed regularly and adjusted to take account of changing facts and circumstances.

A change in estimate of a recognized provision or liability would result in a charge or credit to net income in the period in which the change occurs (with the exception of decommissioning costs as described above).

In particular, provisions for environmental clean-up and remediation costs are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

The provision for environmental liabilities is reviewed at least annually. The interest rate used to determine the balance sheet obligation at December 31, 2005 was 2.0%, the same rate as at the previous balance sheet date.

As further described in Item 18 Financial Statements Note 49 on page F-141, the Group is subject to claims and actions. The facts and circumstances relating to particular cases are evaluated regularly in determining whether it is probable that there will be a future outflow of funds and, once established, whether a provision relating to a specific litigation should be adjusted. Accordingly, significant management judgement relating to contingent liabilities is required, since the outcome of litigation is difficult to predict.

Pensions and Other Postretirement Benefits

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

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

The pension assumptions at December 31, 2005 and 2004 under IAS 19 are summarized below.

	UK		Other		USA	
	2005	2004	2005	2004	2005	2004
			(%)			
Rate of return on assets	7.0	7.0	5.5	6.0	8.0	8.0
Discount rate	4.75	5.25	4.0	5.0	5.5	5.75
Future salary increases	4.25	4.0	3.25	4.0	4.25	4.0
Future pension increases	2.5	2.5	1.75	2.5	nil	nil
Inflation	2.5	2.5	2.0	2.5	2.5	2.5

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

	One-percentage point	
	Increase	Decrease
	($ million)	
Investment return:		
Effect on pension expense in 2006	(346)	348
Discount rate:		
Effect on pension expense in 2006	(78)	93
Effect on pension obligation at December 31, 2005	(4,911)	6,379

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

	2006	2007	2008	2009	2010	2011	2012	2013 and subsequent years
								(%)
Beneficiaries aged under 65	9.0	8.0	7.0	6.0	5.5	5.0	5.0	5.0
Beneficiaries aged over 65	11.0	9.5	8.5	7.5	6.5	6.0	5.5	5.0

The assumed US healthcare cost trend rate has a significant effect on the amounts reported. A one-percentage-point change in the assumed US healthcare cost trend rate would have the following effects:

	One-percentage point	
	Increase	Decrease
	($ million)	
Effect on US postretirement benefit expense in 2006	32	(26)
Effect on US postretirement obligation at December 31, 2005	388	(319)

Impact of New International Financial Reporting Standards

In August 2005, the International Accounting Standards Board (IASB) issued IFRS 7 Financial Instruments Disclosures which is effective for annual periods beginning on or after January 1, 2007, with earlier adoption encouraged. Upon adoption, the Group will disclose additional information about its financial instruments, their significance and the nature and extent of risks to which they give rise. More specifically, the Group will be required to disclose the fair value of its financial instruments and its risk exposure in greater detail. There will be no effect on reported income or net assets. No decision has been made on whether to early adopt this standard.

Also in August 2005, IAS 1 Amendment Presentation of Financial Statements: Capital Disclosures was issued by the IASB, which requires disclosures of an entity s objectives, policies and

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processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements, and the consequences of any non-compliance. This is effective for annual periods beginning on or after January 1, 2007. There will be no effect on the Group s reported income or net assets.

IAS 21 Amendment Net Investment in a Foreign Operation was issued in December 2005. The amendment clarifies the requirements of IAS 21 The Effects of Changes in Foreign Exchange Rates regarding an entity s investment in foreign operations. This amendment is effective for annual periods beginning on or after January 1, 2006, and was adopted by the EU in May 2006. There will be no material impact on the Group s reported income or net assets as a result of adoption of this amendment.

The IASB issued an amendment to the fair value option in IAS 39 Financial Instruments: Recognition and Measurement in June 2005. The option to irrevocably designate, on initial recognition, any financial instruments as ones to be measured at fair value with gains and losses recognized in profit and loss has now been restricted to those financial instruments meeting certain criteria. The criteria are where such designation eliminates or significantly reduces an accounting mismatch, when a group of financial assets, financial liabilities or both are managed and their performance is evaluated on a fair value basis in accordance with a documented risk management or investment strategy, and when an instrument contains an embedded derivative that meets particular conditions. The Group has not designated any financial instruments as being at-fair-value-through-profit-and-loss, thus there will be no effect on the Group s reported income or net assets as a result of adoption of this amendment.

In August 2005, the IASB issued amendments to IAS 39 Financial Instruments: Recognition and Measurement and IFRS 4 Insurance Contracts regarding Financial Guarantee Contracts . These amendments require the issuer of financial guarantee contracts to account for them under IAS 39 as opposed to IFRS 4 unless an issuer has previously asserted explicitly that it regards such contracts as insurance contracts and has used accounting applicable to insurance contracts. In these instances the issuer may elect to apply either IAS 39 or IFRS 4. Under the amended IAS 39, a financial guarantee contract is initially recognized at fair value and is subsequently measured at the higher of (a) the amount determined in accordance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets and (b) the amount initially recognized, less, when appropriate, cumulative amortization recognized in accordance with IAS 18 Revenue . The amendment to IAS 39 is effective for accounting periods beginning on or after January 1, 2006. This standard impacts guarantees given by Group companies in respect of associates and joint ventures as well as in respect of other third parties; these will need to be recorded in the Group s financial statements at fair value.

Several interpretations have been issued by the International Financial Reporting Interpretations Committee (IFRIC) that will become effective for future financial reporting periods.

IFRIC 5 Rights to Interests Arising from Decommissioning, Restoration and Environmental Rehabilitation Funds sets out the accounting and disclosures required with regard to decommissioning funds. This interpretation is effective for annual accounting periods beginning on or after January 1, 2006 and has been adopted by the EU.

IFRIC 6 Liabilities Arising from Participating in a Specific Market Waste Electrical and Electronic Equipment provides guidance on the recognition of liabilities for waste management under the EU Directive on waste electrical and electronic equipment in respect of sales of household equipment before a certain date. This interpretation is effective for annual accounting periods beginning on or after December 1, 2005 and has been adopted by the EU.

IFRIC 7 Applying IAS 29 for the First Time provides detailed guidance on the application of IAS 29 Financial Reporting in Hyperinflationary Economies in the accounting period in which hyperinflation is first observed. This interpretation is effective for annual accounting periods beginning on or after March 1, 2006 and was adopted by the EU in May 2006.

IFRIC 8 Scope of IFRS 2 clarifies that IFRS 2 Share-based Payment is applicable to arrangements where an entity makes share-based payments for nil consideration, or where the consideration is less than the fair value of the options granted. This interpretation is effective for annual accounting periods beginning on or after May 1, 2006 and has yet to be adopted by the EU. This is expected in summer 2006.

IFRIC 9 Reassessment of Embedded Derivatives clarifies that an entity is required to assess whether an embedded derivative should be separated from the host contract and accounted for as a derivative when the entity first becomes a party to the contract. Subsequent reassessment is prohibited unless there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required under the contract, in which case reassessment is required. This interpretation is effective for annual accounting periods beginning on or after June 1, 2006 and has yet to be adopted by the EU. This is expected in summer 2006.

It is not anticipated that any of these interpretations will materially affect the Group s reported income or net assets.

US Generally Accepted Accounting Principles

The consolidated financial statements of the BP Group are prepared in accordance with IFRS, which differs in certain respects from US GAAP. The principal differences between US GAAP and IFRS for BP Group reporting are discussed in Item 18 Financial Statements Note 55 on page F-191.

Impact of New US Accounting Standards

Inventory. In November 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 151 Inventory Costs an amendment of ARB No. 43, Chapter 4 (SFAS 151). SFAS 151 requires that items, such as idle facility expense, excessive spoilage, double freight and re-handling costs, be recognized as current-period charges. SFAS 151 also requires that the allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. SFAS 151 is effective for accounting periods beginning after June 15, 2005. The Group adopted SFAS 151 with effect from July 1, 2005. The adoption of SFAS 151 did not have a significant effect on the Group s profit, as adjusted to accord with US GAAP, or BP shareholders equity, as adjusted to accord with US GAAP.

Discontinued operations. In November 2004, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 03-13 Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations (EITF 03-13). Under EITF 03-13, a disposed component of an enterprise is classified as a discontinued operation only where the ongoing entity has no significant continuing direct cash flows and does not retain an interest, contract or other arrangement sufficient to enable the entity to exert significant influence over the disposed component s operating and financial policies after disposal. EITF 03-13 is effective for a component of an enterprise that is either disposed of or classified as held for sale in accounting periods beginning after December 15, 2004. Applying EITF 03-13 led to the conclusion that the Innovene operations were not discontinued operations for US GAAP (see Item 18 Financial Statements Note 55 on page F-191).

Revenue. In September 2005, the FASB ratified the consensus reached by the EITF regarding Issue No. 04-13 Accounting for Purchases and Sales of Inventory with the Same Counterparty (EITF 04-13). EITF 04-13 addresses accounting issues that arise when a company both sells inventory to and buys inventory from another entity in the same line of business. The purchase and sale transactions may be pursuant to a single contractual arrangement or separate contractual arrangements and the inventory purchased or sold may be in the form of raw material, work-in-process or finished goods. At issue is whether the revenue, inventory cost and cost of sales should be recorded at fair value or whether the transactions should be classified as nonmonetary transactions. EITF 04-13 requires purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another be combined and recorded as exchanges measured at the book value of the item sold. EITF 04-13 is effective for new arrangements entered into and modifications or renewals of existing arrangements in accounting periods beginning after March 15, 2006. The adoption of EITF 04-13 is not expected to have a significant effect on the Group s profit, as adjusted to accord with US GAAP, or shareholders equity, as adjusted to accord with US GAAP.

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

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

Effective January 1, 2005, as part of the adoption of IFRS, the Group adopted International Financial Reporting Standard 2 Share-based Payment (IFRS 2). IFRS 2 requires the recognition of expense when goods or services are received from employees or others in consideration for equity instruments or amounts that are based on the value of an entity s equity instruments. The recognition and measurement provisions of IFRS 2 are similar to those of SFAS 123R.

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

The Group adopted SFAS 123R using the modified prospective transition method with effect from January 1, 2005.

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

In December 2004, the FASB issued Staff Position No. 109-2 Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004 (FSP 109-2). The Jobs Creation Act provides a special one-time provision allowing earnings of certain non-US companies to be repatriated to a US parent company at a reduced tax rate. FSP 109-2, effective upon issuance, permits additional time beyond the financial reporting period of enactment in order to evaluate the effect of the Jobs Creation Act without undermining an entity s assertion that repatriation of non-US earnings to a US parent company is not expected within the foreseeable future. The repatriation provision of the Jobs Creation Act did not have a significant effect on the Group s profit, as adjusted to accord with US GAAP, or BP shareholders equity, as adjusted to accord with US GAAP.

Provisions. In March 2005, the FASB issued FASB Interpretation No. 47 Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143 (Interpretation 47). Under Interpretation 47, a conditional asset retirement obligation represents an unconditional obligation to perform an asset retirement activity where the timing or method of settlement is conditional on a future event that may or may not be within the control of the entity. Interpretation 47 clarifies that an entity is required to recognize a liability, when incurred, for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation is factored into the measurement of the liability when sufficient information exists. SFAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. Interpretation 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. Interpretation 47 is effective for fiscal years ending after December 15, 2005. The Group adopted Interpretation 47 with effect from January 1, 2005. The adoption of Interpretation 47 did not have a significant effect on the Group s profit, as adjusted to accord with US GAAP, or BP shareholders equity, as adjusted to accord with US GAAP.

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

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

BP s accounting policy is that costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. If hydrocarbons are found, and, subject to further appraisal activity which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to property, plant and equipment. The Group adopted FSP 19-1 with effect from January 1, 2004. No previously capitalized costs were expensed upon the adoption of FSP 19-1.

Accounting changes and error corrections. In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154 Accounting Changes and Error Corrections, a replacement of APB

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

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ITEM 6 DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

DIRECTORS AND SENIOR MANAGEMENT

The following lists the Company s directors and senior management as at June 28, 2006.

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

(a) Member of the chairman s committee.

(b) Member of the remuneration committee.

(c) Member of the audit committee.

(d) Member of the ethics and environment assurance committee.

(e) Member of the nomination committee

Mr M H Wilson resigned as a non-executive director on February 28, 2006. Mr H M P Miles retired as a non-executive director on April 20, 2006. At the Company s Annual General Meeting (AGM) the following directors retired, offered themselves for re-election and were duly re-elected: Dr D C Allen, The Lord Browne of Madingley, Mr J H Bryan, Mr A Burgmans, Mr I C Conn, Mr E B Davis, Jr, Mr D J Flint, Dr B E Grote, Dr A B Hayward, Dr D S Julius, Sir Tom McKillop, Mr J A Manzoni, Dr W E Massey, Sir Ian Prosser, and Mr P D Sutherland.

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

P D Sutherland, KCMG Peter Sutherland (60) rejoined BP s board in 1995, having been a non-executive director from 1990 to 1993, and was appointed chairman in 1997. He is non-executive chairman of Goldman Sachs International and a non-executive director of The Royal Bank of Scotland Group.

Sir Ian Prosser Sir Ian (62) joined BP s board in 1997 and was appointed non-executive deputy chairman in 1999. He retired as chairman of Intercontinental Hotels Group PLC, previously Bass PLC, in 2003. He was a non-executive director of The Boots Company from 1984 to 1996, of Lloyds Bank PLC from 1988 to 1995 and of Lloyds TSB Group PLC from 1995 to 1999. In 2000, he was appointed a non-executive director of GlaxoSmithKline and in 2004 he was appointed a non-executive director of Sara Lee Corporation.

The Lord Browne of Madingley, FREng Lord Browne (58) joined BP in 1966 and subsequently held a variety of Exploration and Production and Finance posts in the US, UK and Canada. He was appointed an executive director in 1991 and group chief executive in 1995. He is a non-executive director of Intel Corporation and Goldman Sachs Group Inc. He was knighted in 1998 and made a life peer in 2001.

Dr D C Allen David Allen (51) joined BP in 1978 and subsequently undertook a number of Corporate and Exploration and Production roles in London and New York. He moved to BP s Corporate Planning function in 1986, becoming group vice president in 1999. He was appointed an executive vice president and group chief of staff in 2000 and an executive director of BP in 2003. He is a director of BP Pension Trustees Ltd.

P B P Bevan Peter Bevan (62) joined BP after qualifying as a solicitor with a City of London firm. He worked initially in the law department of BP Chemicals. He became group general counsel in 1992 following roles as manager of the Legal function of BP Exploration, assistant company secretary and deputy group legal adviser. He was appointed an executive vice president of BP p.l.c. in 1998.

S Bott Sally Bott (57) joined BP in March 2005 as an executive vice president responsible for human resources management. She joined Citibank in 1970 and following a variety of roles, was appointed a vice president in human resources in 1979 subsequently holding a series of positions as a human resources director to sectors of Citibank. In 1994, she joined BZW, an investment bank, as head of human resources and in 1996 became group human resources director of Barclays Group. From 2000 to early 2005, she was managing director and head of global human resources at Marsh Inc., insurance brokers.

I C Conn Iain Conn (43) joined BP in 1986. Following a variety of roles in oil trading, commercial refining, marketing, Exploration and Production, in 2000 he became group vice president of BP s Refining and Marketing business. From 2002 to 2004, he was chief executive of Petrochemicals. He was appointed group executive officer with a range of regional and functional responsibilities and an executive director in July 2004. He was appointed to the board of Rolls-Royce Group plc in January 2005. He is chairman of BP Pension Trustees Ltd.

V Cox Vivienne Cox (47) joined BP in 1981. Following a series of commercial roles, she was appointed chief executive of Air BP in 1998. From 1999 until 2001 she was group vice president in BP Oil responsible for business to business marketing in oil, supply and trading. In 2001, she became group vice president integrated supply and trading and in 2004 she was appointed an executive vice president, additionally responsible for Gas, Power and Renewables. She also became responsible for BP Alternative Energy following its launch in late 2005.

Dr B E Grote Byron Grote (58) joined BP in 1987 following the acquisition of The Standard Oil Company of Ohio, where he had worked since 1979. He became group treasurer in 1992 and in 1994 regional chief executive in Latin America. In 1999, he was appointed an executive vice president of Exploration and Production, and chief executive of Chemicals in 2000. He was appointed an executive director of BP in 2000 and chief financial officer in 2002. He was appointed to the boards of Unilever PLC and Unilever NV in May 2006.

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Dr A B Hayward Tony Hayward (49) joined BP in 1982. He became a director of Exploration and Production in 1997, the segment in which he had previously held a series of roles. In 2000, he was made group treasurer and an executive vice president in 2002. He was appointed chief operating officer for Exploration and Production in 2002 and an executive director of BP in 2003. He is a non-executive director of Corus Group.

A G Inglis Andrew Inglis (47) joined BP in 1980 working on various North Sea Projects. Following a series of commercial roles in BP Exploration, in 1996 he became chief of staff, Exploration and Production. From 1997 until 1999, he was responsible for leading BP s activities in the Deepwater Gulf of Mexico. In 1999, he was appointed vice president of BP s US western gas business unit and in 2004 he became executive vice president and deputy chief executive of Exploration and Production.

J A Manzoni John Manzoni (46) joined BP in 1983. He became group vice president for European marketing in 1999 and BP regional president for the eastern US in 2000. In 2001, he became an executive vice president and chief executive for BP s Gas and Power segment. He was appointed chief executive of the Refining and Marketing segment in 2002 and an executive director of BP in 2003. He is a non-executive director of SABMiller plc.

J H Bryan John Bryan (69) joined BP s board in 1998, having previously been a director of Amoco. He serves on the boards of General Motors Corporation and Goldman Sachs Group Inc. He retired as chairman of Sara Lee Corporation in 2001. He is chairman of Millennium Park Inc. in Chicago.

A Burgmans Antony Burgmans (59) joined BP s board in 2004. He was appointed to the board of Unilever in 1991. In 1999, he became chairman of Unilever NV and vice chairman of Unilever PLC. He was appointed non-executive chairman of Unilever NV and Unilever PLC in 2005. He is also a member of the supervisory board of ABN AMRO Bank NV.

E B Davis, Jr Erroll B Davis, Jr (61) joined BP s board in 1998, having previously been a director of Amoco. He was chairman and chief executive officer of Alliant Energy, relinquishing this dual appointment in July 2005. He continued as chairman of Alliant Energy until February 1, 2006, leaving to become chancellor of the University System of Georgia. He is a non-executive director of PPG Industries, Union Pacific Corporation and the US Olympic Committee.

D J Flint, CBE Douglas Flint (50) joined BP s board in January 2005. He trained as a chartered accountant and became a partner at KPMG in 1988. In 1995, he was appointed group finance director of HSBC Holdings plc. He was chairman of the Financial Reporting Council s review of the Turnbull Guidance on Internal Control. Between 2001 and 2004, he served on the Accounting Standards Board and the advisory council of the International Accounting Standards Board.

Dr D S Julius, CBE DeAnne Julius (57) joined BP s board in 2001. She began her career as a project economist with the World Bank in Washington. From 1986 until 1997, she held a succession of posts, including chief economist at British Airways and Royal Dutch Shell Group. From 1997 to 2001, she was a full-time member of the Monetary Policy Committee of the Bank of England. She is chairman of the Royal Institute of International Affairs and a non-executive director of Lloyds TSB Group PLC, Serco and Roche Holdings SA.

Sir Tom McKillop Sir Tom (63) joined BP s board in July 2004. Sir Tom was chief executive of AstraZeneca PLC from the merger of Astra AB and Zeneca Group PLC in 1999 until December 31, 2005. He was a non-executive director of Lloyds TSB Group PLC until 2004 and is chairman of The Royal Bank of Scotland Group.

Dr W E Massey Walter Massey (68) joined BP s board in 1998, having previously been a director of Amoco. He is president of Morehouse College, a non-executive director of Motorola, Bank of America and McDonald s Corporation and a member of President Bush s Council of Advisors on Science & Technology.

COMPENSATION

The remuneration committee determines the terms of engagement and remuneration of the executive directors and monitors the policies applied by the group chief executive in remunerating other senior executives.

Policy on Executive Directors Remuneration

During 2004, the committee carried out a comprehensive and independent review of all elements of remuneration policy for executive directors, culminating in a shareholder resolution at the 2005 AGM approving the renewal of the Executive Directors Incentive Plan (EDIP).

The committee seeks to ensure that, in determining remuneration policy, there is a clear link between the Company s purpose, the business plans and executive reward. The following key principles guide its policy:

- Policy for the remuneration of executive directors will be determined and regularly reviewed independently of executive management and will set the tone for the remuneration of other senior executives.
- The remuneration structure will support and reflect BP s stated purpose to maximize long-term shareholder value.
- The remuneration structure will reflect a just system of rewards for the participants.
- The overall quantum of all potential remuneration components will be determined by the exercise of informed judgement of the independent remuneration committee, taking into account the success of BP and the competitive global market.
- The majority of the remuneration will be linked to the achievement of demanding performance targets that are independently set and reflect the creation of long-term shareholder value.
- A significant personal shareholding will be developed in order to align executive and shareholder interests.
- Assessment of performance will be quantitative and qualitative and will include exercise of informed judgement by the remuneration committee within a framework that takes account of sector characteristics and is approved by shareholders.
- The committee will be proactive in obtaining an understanding of shareholder preferences.
- Remuneration policy and practices will be as transparent as possible, both for participants and shareholders.
- The wider scene, including pay and employment conditions elsewhere in the Group, will be taken into account, especially when determining annual salary increases.

Elements of Remuneration

The executive directors total remuneration will consist of salary, annual bonus, long-term incentives, pensions and other benefits. This reward structure will be regularly reviewed by the committee to ensure that it is achieving its objectives.

In 2006, over three-quarters of executive directors potential direct remuneration will again be performance-related.

Salary

The committee expects to review salaries in 2006. In doing so, the committee considers both top Europe-based global companies and the US oil and gas sector; each of these groups is defined and analysed by the committee s independent external remuneration advisers. The committee then assesses the market information and advice and applies its judgement in setting the salary levels.

Annual Bonus

Each executive director is eligible to participate in an annual performance-based bonus scheme. The committee reviews and sets bonus targets and levels of eligibility annually.

For 2006, the target level is 120% of base salary (except for Lord Browne, for whom, as group chief executive, it is considered appropriate to have a target of 130%). In normal circumstances, the maximum payment level for substantially exceeding targets will continue to be 150% (165% for the group chief executive) of base salary. In exceptional circumstances, outstanding performance may be recognized by bonus payments moderately above the 150% (and 165%) levels at the discretion of the remuneration committee. Similarly, bonuses may be reduced where the committee considers that this is warranted and, in exceptional circumstances, bonuses can be reduced to zero.

The committee recognizes that it is responsible to shareholders to use its discretion in a reasonable and informed manner in the best interests of the Company and that it has a corresponding duty to be accountable and transparent as to the manner in which it exercises its discretion. The committee will explain any significant exercise of discretion in the subsequent directors remuneration report.

Executive directors annual bonus awards for 2006 will be based on a mix of demanding financial targets, based on the Company s annual plan and leadership objectives established at the beginning of the year, in accordance with the following weightings:

50% financial and operational metrics from the annual plan, principally earnings before interest, tax, depreciation and amortization (EBITDA) and return on average capital employed (ROACE).

30% annual strategic milestones taken from the five-year Group business plan, including those relating to technology, operational actions and business development.

20% individual performance against leadership objectives and living the values of the Group, which incorporates BP s Code of Conduct.

In assessing the final outcome of the individual bonuses each year, the committee will also carefully review the underlying performance of the Group in the context of the five-year Group business plan, as well as looking at competitor results, analysts reports and the views from the chairmen of other BP board committees. All the calculations are reviewed by Ernst & Young.

Long-term Incentives

Long-term incentives will continue to be provided under the EDIP. It has three elements within its framework: a share element, a share option element and a cash element. The committee does not currently intend to use either the share option or cash elements but, in exceptional circumstances, may do so.

Each executive director participates in the EDIP. The committee s policy, subject to unforeseen circumstances, is that this should continue until the EDIP expires or is renewed in 2010.

The committee s policy continues to be that each executive director should hold shares equivalent in value to 5 x the director s base salary within five years of being appointed an executive director. This policy is reflected in the terms of the EDIP, as shares awarded under the share element will only be released at the end of the three-year retention period (as described below) if the minimum shareholding guidelines have been met.

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Share Element

The committee may make conditional share awards (performance shares) to executive directors, which will only vest to the extent that a demanding performance condition imposed by the committee is met at the end of a three-year performance period.

The maximum number of performance shares that may be awarded to an executive director in any one year will be determined at the discretion of the remuneration committee and will not normally exceed 5.5 x base salary and, in the case of the group chief executive, 7.5 x base salary.

In addition to the performance condition described below, the committee will have an overriding discretion, in exceptional circumstances, to reduce the number of shares that vest (or to provide that no shares vest).

The shares that vest will normally be subject to a compulsory retention period determined by the committee, which will not normally be less than three years. This gives executive directors a six-year incentive structure and is designed to ensure that their interests are aligned with those of shareholders. Where shares vest under awards made in 2005 and future years, the executive director will receive additional shares representing the value of reinvested dividends on these shares.

For share element awards in 2006, the performance condition will (as in 2005) relate to BP s total shareholder return (TSR) performance against the other oil majors (ExxonMobil, Shell, Total and Chevron) over a three-year period. The committee will have the discretion to amend this peer group in appropriate circumstances, for example, in the case of any significant consolidations in the industry. TSR is calculated by taking the share price performance of a company over the period, assuming dividends to be reinvested in the Company s shares. All share prices will be averaged over the three months before the beginning and end of the performance period and will be measured in US dollars. At the end of the performance period, the TSR performance of each of the companies will be ranked to establish the relative total return to shareholders over the period. Shares under the award will vest as to 100%, 70% and 35% if BP achieves first, second or third place respectively; no shares will vest if BP achieves fourth or fifth place.

The committee considers that relative TSR is the most appropriate measure of performance for BP s long-term incentives for executive directors as it best reflects the creation of long-term shareholder value. Relative performance of the peer group is particularly key in order to minimize the influence of sector-specific effects, including oil price.

The committee is mindful of the possibility that a simple ranking system may in some circumstances give rise to distorted results in view of the broad similarity of the oil majors underlying businesses, the small size of the comparator group and inherent imperfections in measurement. To counter this, the committee will have the ability to exercise discretion in a reasonable and informed manner to adjust (upwards or downwards) the vesting level derived from the ranking if it considers that the ranking does not fairly reflect BP s underlying business performance relative to the comparator group.

The exercise of this discretion would be made after a broad analysis of the underlying health of BP s business relative to competitors, as shown by a range of other measures including, but not limited to, ROACE, earnings per share (EPS) growth, reserves replacement and cash flow. This will enable a more comprehensive review of long-term performance, with the aims of tempering anomalies created by relying solely on a formula-based approach and ensuring that the objectives of the plan are met.

It is anticipated that the need to use discretion is most likely to arise where the TSR performance of some companies is clustered, so that a relatively small difference in TSR performance would produce a major difference in vesting levels. In these circumstances, the committee will have power to adjust the vesting level, normally by determining an average vesting level for the companies affected by the clustering.

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In line with its policy on transparency, the committee will explain any adjustment to the relative TSR ranking in the next directors remuneration report following the vesting.

The committee may amend the performance conditions if events occur that would make the amended condition a fairer measure of performance and provided that any amended condition is no easier to satisfy.

For 2006, all executive directors will receive performance share awards on the above basis, over a maximum number of shares set by reference to 5.5 x base salary. For awards under the share element in future years, the committee may continue with the same performance condition or may impose a different condition, which it considers to be no less demanding.

As group chief executive, Lord Browne is eligible for performance share awards of up to 7.5 x base salary. The committee has determined that, while the largest part of this should relate to the TSR measure described above, it continues to be appropriate that a specific part (up to 2 x base salary) should be based on long-term leadership measures. These will focus on sustaining BP s financial, strategic and organizational health and will include, but not be limited to, maintenance of BP s performance culture and the continued development of BP s business strategy, executive talent and internal organization. As with the TSR part of his award, this part will be measured over a three-year performance period.

Share Element Awards Made in Previous Years

Awards for the period 2005-2007 were made on the same basis as described above. For outstanding awards of performance units made under the plans for the periods 2003-2005 and 2004-2006, the previous performance conditions will apply for the three-year performance periods in each of the plans. The primary measure is BP s shareholder return against the market (SHRAM), which accounts for nearly two-thirds of the potential total award, the remainder being assessed on BP s relative ROACE and EPS growth.

BP s SHRAM is measured against the companies in the FTSE All World Oil & Gas Index. Companies within the index are weighted according to their market capitalization at the beginning of each three-year period in order to give greatest emphasis to oil majors. BP s ROACE and EPS growth are measured against ExxonMobil, Shell, Total and Chevron. All calculations are reviewed by Ernst & Young to ensure that they meet an independent objective standard. The relative position of the Company within the comparator group determines the number of shares awarded per performance unit, subject to a maximum of two shares per unit.

Share Option Element

The share option element of the EDIP permits options to be granted to executive directors at an exercise price no lower than the market value of a share at the date the option is granted. The committee does not currently intend to use this element.

Cash Element

The cash element allows the committee to grant long-term cash-based incentives. This element has not been used since the EDIP was established in 2000 and the committee would only do so in special circumstances.

Pensions

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

Other Benefits

Benefits and Other Share Schemes

Executive directors are eligible to participate in regular employee benefit plans and in all-employee share schemes and savings plans applying in their home countries. Benefits in kind are not pensionable.

Resettlement Allowance

Expatriates may receive a resettlement allowance for a limited period.

2005 Remuneration for Executive Directors

Amounts shown are in the currency received by executive directors. For information, the average exchange rate for 2005 was £1 = $1.82. Annual bonus is shown in the year it was earned.

	Annual remuneration					Long-term remuneration				
						Share element of EDIP/ LTPPs				
						2002-2004 plan (vested in Feb 2005)		2003-2005 plan (vested in Feb 2006)		2005-2007 plan (awarded in Apr 2005)
	2005 Salary 000	2005 annual performance bonus 000	2005 Non-cash benefits and other emoluments 000	2005 total 000	2004 total 000	Actual Shares vested(b)	Value 000(a)	Actual shares vested (b)	Value 000(c)	Potential maximum performance shares (d)
The Lord Browne of Madingley	£1,451	£1,750	£90	£3,291	£3,744	356,667	£1,958	474,384	£3,064	2,006,767
Dr D C Allen	£431	£480	£12	£923	£1,036	60,000	£329	147,783	£955	436,623
I C Conn(e)	£421	£450	£43	£914	£542	51,750	£284	68,250	£441	415,832
Dr B E Grote	$923	$1,100		$2,023	$2,103	136,960	$1,419	175,229	$1,979	501,782
Dr A B Hayward	£431	£460	£14	£905	£1,061	55,125	£303	147,783	£955	436,623
J A Manzoni	£431	£440	£47	£918	£1,071	60,000	£329	147,783	£955	436,623

(a) Based on market price on date of award (£5.49 per share/$62.15 per ADS).

(b) Gross award of shares based on a performance assessment by the remuneration committee and on the other terms of the plan. Sufficient shares are sold to pay for tax applicable. Remaining shares are held in trust for current directors for the three-year retention period, when they are released to the individual.

(c) Based on the market price on date of award (£6.46 per share/$67.76 per ADS).

(d) Maximum potential shares that could vest at the end of the three-year period depending on performance.

(e) 2004 remuneration reflects that received by Mr Conn from his appointment as executive director on July 1, 2004.

Salary

Base salaries for all executive directors were reviewed relative to top Europe-based global companies and the US oil and gas sector. Having taken account of market movements and performance, the committee awarded a 5% increase in base salaries with effect from July 1, 2005 for all executive directors except Mr Conn, whose increase was slightly higher to bring him to the same level as his peers.

Annual Bonus

The measures and weightings described earlier form the framework within which the remuneration committee determined the annual bonuses for the executive directors.

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The committee made evaluations against each of the measures: financial, metrics and milestones, and individual. The financial measures were taken from the annual plan principally on cash flow. Cash flow was strong. Amounts received from the divestment of non-strategic assets significantly exceeded internal targets (principally due to the Innovene disposal) and these, along with other actions and successes, more than offset reductions in cash flow caused by adverse events. Production rates, allowing for the impact of oil prices on production-sharing contracts and weather-related downtime, were within internal expectations.

Annual strategic metrics and milestones were taken from the five-year Group business plan. There is a wide range of measures, including those relating to people, safety, environment, technology and organization as well as operations and business development. The Group continued to perform well, developing business in Russia, India and elsewhere. New fields came on stream in the US, Angola, Azerbaijan and Trinidad & Tobago. A new Code of Conduct was launched and employees were trained in its application. Safety performance was impaired by the incident at the Texas City refinery.

Individual performance against leadership objectives was reviewed by the committee, as was the underlying performance of the Group in the context of the five-year plan, together with competitor results and positioning. Results are in line with or exceed expectations.

The committee also considered this performance in the light of the significant events during the year, both positive and negative. These included the high prices of oil and gas; the overall financial performance of the Group; the disposal of non-strategic assets, principally Innovene; the financial and other consequences of the incident at the Texas City refinery and the repairs to the Thunder Horse platform; and the effects of the hurricanes in the Gulf of Mexico. The scale and the impact of all of these events were taken into account in determining the annual bonuses.

Long-term Performance-based Components

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

Under the share element of the EDIP and the Long Term Performance Plans (LTPPs), performance units were until 2004 granted at the beginning of the three-year period and converted into an award of shares at the end of the period, depending on performance. There is a maximum of two shares per performance unit. For 2005 and future years, grants of performance shares are made, being the maximum number of shares that could vest (as described in compensation Elements of Remuneration Long-Term Incentives Share Element in this Item on page 117). In the table following, performance units that have yet to convert to shares are expressed as the maximum number of shares into which they could convert (based on the maximum 2:1 ratio). This achieves consistency of disclosure between the two periods.

For the 2003-2005 share element of the EDIP and the LTPPs, BP s performance was assessed in terms of SHRAM, ROACE and EPS growth. BP s three-year SHRAM was measured against the companies in the FTSE All World Oil & Gas Index. Companies within the index are weighted according to their market capitalization at the beginning of each three-year period in order to give greatest emphasis to oil majors. BP s ROACE and EPS were measured against ExxonMobil, Shell, Total and Chevron. Based on a performance assessment of 75 points out of 200 (0 for SHRAM, 50 for ROACE and 25 for EPS growth), the committee made awards of shares to executive directors as highlighted in the 2003-2005 lines of the table following.

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The following table summarizes the LTPPs and share elements of the executive directors remuneration for 2005.

	Performance period	Date of award of performance shares	Market price of each share at date of award of performance shares £	Share element/ LTPP interests: Potential maximum performance shares (a): At Jan 1, 2005	Awarded 2005	At Dec 31, 2005	Interests vested in 2005: Number of ordinary shares vested (b)	Vesting date	Market price of each share at vesting date £
The Lord Browne of Madingley	2002-2004	Feb 18, 2002	5.73	951,112			356,667	Feb 9, 2005	5.49
	2003-2005	**Feb 17, 2003**	**3.96**	**1,265,024**		**1,265,024**	**474,384**	**Feb 13, 2006**	**6.46**
	2004-2006	Feb 25, 2004	4.25	1,268,894		1,268,894			
	2005-2007	Apr 28, 2005	5.33		2,006,767	2,006,767			
Dr D C Allen	2002-2004	Mar 6, 2002	5.99	160,000			60,000	Feb 9, 2005	5.49
	2003-2005	**Feb 17, 2003**	**3.96**	**394,088**		**394,088**	**147,783**	**Feb 13, 2006**	**6.46**
	2004-2006	Feb 25, 2004	4.25	376,470		376,470			
	2005-2007	Apr 28, 2005	5.33		436,623	436,623			
I C Conn (c)	2002-2004	Mar 6, 2002	5.99	138,000			51,750	Feb 9, 2005	5.49
	2003-2005	**Feb 17, 2003**	**3.96**	**182,000**		**182,000**	**68,250**	**Feb 13, 2006**	**6.46**
	2004-2006	Feb 25, 2004	4.25	182,000		182,000			
	2005-2007	Apr 28, 2005	5.33		415,832	415,832			
Dr B E Grote	2002-2004	Feb 18, 2002	5.73	365,226			136,960	Feb 9, 2005	5.49
	2003-2005	**Feb 17, 2003**	**3.96**	**467,276**		**467,276**	**175,229**	**Feb 13, 2006**	**6.46**
	2004-2006	Feb 25, 2004	4.25	425,338		425,338			
	2005-2007	Apr 28, 2005	5.33		501,782	501,782			
Dr A B Hayward	2002-2004	Mar 6, 2002	5.99	147,000			55,125	Feb, 9 2005	5.49
	2003-2005	**Feb 17, 2003**	**3.96**	**394,088**		**394,088**	**147,783**	**Feb 13, 2006**	**6.46**
	2004-2006	Feb 25, 2004	4.25	376,470		376,470			
	2005-2007	Apr 28, 2005	5.33		436,623	436,623			
J A Manzoni	2002-2004	Mar 6, 2002	5.99	160,000			60,000	Feb 9, 2005	5.49
	2003-2005	**Feb 17, 2003**	**3.96**	**394,088**		**394,088**	**147,783**	**Feb 13, 2006**	**6.46**
	2004-2006	Feb 25, 2004	4.25	376,470		376,470			
	2005-2007	Apr 28, 2005	5.33		436,623	436,623			

Former Directors									
R L Olver	2002-2004	Feb 18, 2002	5.73	392,592			147,222	Feb 9, 2005	5.49
	2003-2005	**Feb 17, 2003**	**3.96**	**548,276**		**548,276**	**205,604**	**Feb 13, 2006**	**6.46**

(a) BP s performance is measured against the oil sector. For the periods 2003-2005 and 2004-2006, the performance measure is SHRAM, which is measured against the FTSE All World Oil & Gas Index, and ROACE and EPS growth, which are measured against ExxonMobil, Shell, Total and Chevron. For the 2005-2007 period, the performance condition is TSR measured against ExxonMobil, Shell, Total and Chevron. Each performance period ends on December 31 of the third year.

(b) Represents awards of shares made at the end of the relevant performance period based on performance achieved under rules of the plan.

(c) Mr Conn elected to defer to 2006 the determination of whether LTPP awards should be made for the 2000-2002 performance period. As this period ended prior to his appointment as a director, the award is not included in this table.

Share Options

The table below represents the interests of executive directors in options over ordinary shares during 2005.

	Option type	At Jan 1, 2005	Granted	Exercised	At Dec 31, 2005	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
The Lord Browne of Madingley	SAYE	4,550			4,550	£3.50		Sept 1, 08	Feb 28, 09
	EDIP	408,522			408,522	£5.99		May 15, 01	May 15, 07
	EDIP	1,269,843			1,269,843	£5.67		Feb 19, 02	Feb 19, 08
	EDIP	1,348,032			1,348,032	£5.72		Feb 18, 03	Feb 18, 09
	EDIP	1,348,032			1,348,032	£3.88		Feb 17, 04	Feb 17, 10
	EDIP	1,500,000			1,500,000	£4.22		Feb 25, 05	Feb 25, 11
Dr D C Allen	EXEC	37,000			37,000	£5.99		May 15, 03	May 15, 10
	EXEC	87,950			87,950	£5.67		Feb 23, 04	Feb 23, 11
	EXEC	175,000			175,000	£5.72		Feb 18, 05	Feb 18, 12
	EDIP	220,000			220,000	£3.88		Feb 17, 04	Feb 17, 10
	EDIP	275,000			275,000	£4.22		Feb 25, 05	Feb 25, 11
I C Conn	SAYE	1,355		1,355		£4.98	£6.38	Sep 1, 05	Feb 28, 06
	SAYE	1,456			1,456	£3.50		Sep 1, 08	Feb 28, 09
	SAYE	1,186			1,186	£3.86		Sep 1, 09	Feb 28, 10
	SAYE		1,498		1,498	£4.41		Sep 1, 10	Feb 28, 11
	EXEC	72,250			72,250	£5.67		Feb 23, 04	Feb 23, 11
	EXEC	130,000			130,000	£5.72		Feb 18, 05	Feb 18, 12
	EXEC	160,000			160,000	£3.88		Feb 17, 06	Feb 17, 13
	EXEC	126,000			126,000	£4.22		Feb 25, 07	Feb 25, 14
Dr B E Grote (a)	SAR	35,200			35,200	$25.27		Mar 6, 99	Mar 6, 06
	SAR	40,000			40,000	$33.34		Feb 28, 00	Feb 28, 07
	BPA	10,404			10,404	$53.90		Mar 15, 00	Mar 14, 09
	BPA	12,600			12,600	$48.94		Mar 28, 01	Mar 27, 10
	EDIP	40,182			40,182	$49.65		Feb 19, 02	Feb 19, 08
	EDIP	58,173			58,173	$48.82		Feb 18, 03	Feb 18, 09
	EDIP	58,173			58,173	$37.76		Feb 17, 04	Feb 17, 10
	EDIP	58,333			58,333	$48.53		Feb 25, 05	Feb 25, 11
Dr A B Hayward	SAYE	3,302			3,302	£5.11		Sept 1, 06	Feb 28, 07
	EXEC	34,000			34,000	£5.99		May 15, 03	May 15, 10
	EXEC	77,400			77,400	£5.67		Feb 23, 04	Feb 23, 11
	EXEC	160,000			160,000	£5.72		Feb 18, 05	Feb 18, 12
	EDIP	220,000			220,000	£3.88		Feb 17, 04	Feb 17, 10
	EDIP	275,000			275,000	£4.22		Feb 25, 05	Feb 25, 11
J A Manzoni	SAYE	878			878	£4.52		Sept 1, 07	Feb 28, 08

SAYE	2,548		2,548	£3.50		Sept 1, 08	Feb 28, 09
SAYE	847		847	£3.86		Sept 1, 09	Feb 28, 10
EXEC	12,000	12,000		£2.04	£5.52	Feb 28, 98	Feb 28, 05
EXEC	34,000		34,000	£5.99		May 15, 03	May 15, 10
EXEC	72,250		72,250	£5.67		Feb 23, 04	Feb 23, 11
EXEC	175,000		175,000	£5.72		Feb 18, 05	Feb 18, 12
EDIP	220,000		220,000	£3.88		Feb 17, 04	Feb 17, 10
EDIP	275,000		275,000	£4.22		Feb 25, 05	Feb 25, 11

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The closing market prices of an ordinary share and of an ADS on December 31, 2005 were £6.19 and $64.22 respectively. During 2005, the highest closing market prices were £6.84 and $72.27 respectively and the lowest closing market prices were £5.04 and $56.61 respectively.

EDIP	Executive Directors Incentive Plan adopted by shareholders in April 2005 as described in Compensation Elements of Remuneration Long-Term Incentives in this Item on page 116.
BPA	BP Amoco share option plan, which applied to US executive directors prior to the adoption of the EDIP.
SAR	Stock Appreciation Rights under BP America Inc. Share Appreciation Plan.
SAYE	Save As You Earn employee share scheme.
EXEC	Executive Share Option Scheme. These options were granted to the relevant individuals prior to their appointments as directors and are not subject to performance conditions.

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

Pensions

In the table below, amounts are shown in the currency received. For information, the average exchange rate for 2005 was £1 = $1.82. Lord Browne, Dr Allen, Mr Conn, Dr Hayward and Mr Manzoni accrued pension benefits in pounds sterling (the currency of payment). Similarly, Dr Grote accrued pension benefits in US dollars.

	Service at Dec 31, 2005	Accrued pension entitlement at Dec 31, 2005	Additional pension earned during the year ended Dec 31, 2005 (a)	Transfer value of accrued benefit (b) at Dec 31, 2004 A	Transfer value of accrued benefit (b) at Dec 31, 2005 B	Amount of B-A less contributions made by the director in 2005
				(thousand)		
The Lord Browne of Madingley (UK)	39 years	£991	£47	£17,170	£19,979	£2,809
Dr D C Allen (UK)	27 years	£200	£17	£2,754	£3,433	£679
I C Conn (UK)	20 years	£147	£20	£1,542	£2,124	£582
Dr B E Grote (US)	26 years	$570	$105	$5,529	$6,681	$1,152
Dr A B Hayward (UK)	24 years	£207	£19	£2,680	£3,408	£728
J A Manzoni (UK)	22 years	£163	£15	£1,958	£2,518	£560

(a) Additional pension earned during the year includes an inflation increase of 3.5%.

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

UK Directors

UK directors are members of the regular BP Pension Scheme. Scheme members core benefits are non-contributory. They include a pension accrual of 1/60th of basic salary for each year of service, subject to a maximum of two-thirds of final basic salary, and a dependant s benefit of two-thirds of the member s pension. Bonuses are not pensionable for UK directors. The scheme pension is not integrated with state pension benefits.

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

In accordance with the Company s past practice for executive directors who retire from BP on or after age 55 having accrued at least 30 years service, Lord Browne remains eligible for consideration for a payment from the Company of an ex-gratia lump-sum superannuation payment equal to one year s base salary following his retirement. All matters relating to such superannuation payments are considered by the remuneration committee. Any such payment would be additional to his pension entitlements referred to above. No other executive director is eligible for consideration for a superannuation payment on retirement, because the remuneration committee decided in 1996 that appointees to the board after that time should cease to be eligible for consideration for such a payment.

The UK government has made important changes to the operation and taxation of UK pensions, which come into effect from April 6, 2006 and affect all UK employees. The remuneration committee has reviewed and approved proposals by the Company that maintain the pension promise for all UK employees but that deliver pension benefits in excess of the new lifetime allowance of £1.5 million (or personal lifetime allowance as at April 6, 2006 under statute if higher) via an unapproved, unfunded pension arrangement paid by the Company direct.

The trustee directors of the BP Pension Scheme have reviewed, in accordance with its statutory obligation, the actuarial basis under which cash equivalent transfer values are payable to all UK employees who participate in that scheme. Consistent with evolving actuarial practice, the trustee directors have resolved to base cash equivalent transfer values on a similar basis to that underlying the Company s accounts, including allowance for improving longevity in accordance with standard tables; this has the effect of increasing cash equivalent transfer values for the UK executive directors on average by about 15%. Although the change became effective in January 2006, the table above shows both December 31, 2004 and December 31, 2005 transfer value figures on the new basis.

US Director

As a US director, Dr Grote participates in the US BP Retirement Accumulation Plan (US plan), which features a cash balance formula. The current design of the US plan became effective on July 1, 2000.

Consistent with US tax regulations, pension benefits are provided through a combination of tax-qualified and non-qualified benefit restoration plans, as applicable.

The Supplemental Executive Retirement Benefit (supplemental plan) is a non-qualified top-up arrangement that became effective on January 1, 2002 for US employees above a specified salary level.

The benefit formula is 1.3% of final average earnings, which comprise base salary and bonus in accordance with standard US practice (as specified under the qualified arrangement) multiplied by years of service, with an offset for benefits payable under all other BP qualified and non-qualified pension arrangements. This benefit is unfunded and therefore paid from corporate assets.

Dr Grote is an eligible participant under the supplemental plan and his pension accrual for 2005 includes the total amount that may become payable under all plans.

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Executive Directors Shareholdings

Executive directors interest in BP ordinary shares or calculated equivalents	At January 1, 2005	At December 31, 2005	At June 28, 2006
Current directors			
Dr D C Allen	408,342	443,742	530,933 (a)
The Lord Browne of Madingley	2,031,279	2,242,954	2,522,840 (b)
I C Conn	121,187	156,349	206,642 (c)
Dr B E Grote	888,213	988,906	1,092,292 (d)
Dr A B Hayward	206,084	305,543	399,466
J A Manzoni	196,336	275,743	369,191

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

(b) Includes 58,713 shares held as ADSs.

(c) Includes 39,466 shares held as ADSs.

(d) Held as ADSs

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

Executive directors are also deemed to have an interest in such shares of the Company held from time to time by The BP Employee Share Ownership Plan (No. 2) to facilitate the operation of the Company s option schemes.

No director has any interest in the preference shares or debentures of the Company, or in the shares or loan stock of any subsidiary company.

Past Directors

During 2005, Mr Olver continued as a consultant to BP in relation to its activities in Russia and served as a BP-nominated director of TNK-BP Limited, a joint venture company owned 50% by BP. Under the consultancy agreement, he received £300,000 in fees in 2005 as well as reimbursement of costs and support for his role. He is also entitled to retain fees paid to him by TNK-BP up to a maximum of $120,000 a year for his role as a director, deputy chairman and chairman of the audit committee of TNK-BP Limited.

Policy on Non-Executive Directors Remuneration

The board sets the level of remuneration for all non-executive directors within the limit approved from time to time by shareholders. In line with BP s governance policies, the remuneration of the chairman is set by the board rather than the remuneration committee, since the performance of the chairman is a matter for the board as a whole rather than any one committee.

The board has adopted the following policies to guide its current and future decision-making with regard to non-executive directors remuneration:

Within the limits set by the shareholders from time to time, remuneration should be sufficient to attract, motivate and retain world-class non-executive talent.

Remuneration of non-executive directors is set by the board and should be proportional to their contribution towards the interests of the Company.

Remuneration practice should be consistent with recognized best-practice standards for non-executive directors remuneration.

Remuneration should be in the form of cash fees, payable monthly.

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Non-executive directors should not receive share options from the Company.

Non-executive directors should be encouraged to establish a holding in BP shares broadly related to one year s base fee, to be held directly or indirectly in a manner compatible with their personal investment activities, and any applicable legal and regulatory requirements.

Elements of Remuneration

Non-executive directors pay comprises cash fees, paid monthly, with increments for positions of additional responsibility, reflecting additional workload and consequent potential liability. For all non-executive directors, except the chairman, a fixed sum allowance is paid for transatlantic travel (or equivalent intercontinental travel) undertaken for the purpose of attending a board or board committee meeting. In addition, non-executive directors receive reimbursement of reasonable travel and related business expenses. No share or share option awards are made to any non-executive director in respect of service on the board.

Letters of Appointment

Non-executive directors have letters of appointment, which recognize that, subject to the Articles of Association, their service is at the discretion of the shareholders. All directors stand for re-election at each annual general meeting.

Non-Executive Directors Annual Fee Structure

The fees paid to non-executive directors are set by the board within the limit set by shareholders in accordance with the Articles. Shareholders approved an increase to this limit in 2004. All fees are fixed and paid in pounds sterling. Fees payable to non-executive directors were reviewed in 2005 by an ad hoc board committee comprising Mr Bryan (chairman), Dr Julius and Mr Burgmans. This ad hoc committee recommended an increase in fees to reflect the increase in director workload as well as increases in global market rates for independent/non-executive directors, since these fees were last reviewed in 2002. The board duly approved the recommended increases with effect from January 1, 2005.

	Year ended December 31,	
	2005	**2004**
	(£ thousands)	
Chairman (a)	500 (a)	390
Deputy chairman (b)	100 (b)	85
Board member	75	65
Committee chairmanship fee	20	15
Transatlantic attendance allowance (c)	5	5

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

(b) The deputy chairman receives a £25,000 (2004 £20,000) increment on top of the standard board fee. In addition, he is eligible for committee chairmanship fees and the transatlantic attendance allowance. The deputy chairman is currently chairman of the audit committee.

(c) This allowance is payable to non-executive directors undertaking transatlantic or equivalent intercontinental travel for the purpose of attending a board meeting or board committee meeting.

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	Year ended December 31,			
	2005		2004	
Remuneration of Non-Executive Directors				
	($ thousand) (a)	**(£ thousands)**	**($ thousands) (b)**	**(£ thousands)**
J H Bryan	200	110	183	100
A Burgmans	164	90	97	53
E B Davis, Jr	200	110	192	105
D J Flint (c)	164	90	n/a	n/a
Dr D S Julius	195	107	137	75
Sir Tom McKillop	164	90	70	38
Dr W E Massey	237	130	210	115
H M P Miles *	164	90	137	75
Sir Ian Prosser	246	135	201	110
P D Sutherland	910	500	714	390
M H Wilson	191	105	174	95
Directors who left the board in 2005				
C F Knight (d)(e)	55	30	165	90
Sir Robin Nicholson (d)(f)(g)	58	32	165	90

(a) Sterling payments converted at the average 2005 exchange rate of £1 = $1.82.

(b) Sterling payments converted at the average 2004 exchange rate of £1 = $1.83.

(c) Appointed on January 1, 2005

(d) Retired at AGM on April 14, 2005

(e) Also received a superannuation gratuity of £79,000 following his retirement.

(f) Also received £20,000 each year for serving as the board s representative on the BP technology advisory council.

(g) Also received a superannuation gratuity of £84,000 following his retirement.

* Retired at AGM on April 20, 2006

Resigned as a non-executive director on February 28, 2006

Long-Term Incentives (Residual)

Non-executive directors of Amoco Corporation were allocated restricted stock in the Amoco Non-Employee Directors Restricted Stock Plan by way of remuneration for their service on the board of Amoco Corporation prior to its merger with BP in 1998. On merger, interests in Amoco shares in the plan were converted into interests in BP ADSs. Under the terms of the plan, the restricted stock will vest on the retirement of the non-executive director having reached age 70 or on earlier retirement at the discretion of the board. Since the merger, no further entitlements have accrued to any director under the plan.

Amoco Non-Employee Directors Restricted Stock Plan

The table below sets out the residual entitlements of non-executive directors who were formerly non-executive directors of Amoco Corporation under the Amoco Non-Employee Directors Restricted Stock Plan.

	Interest in BP ADSs at January 1, 2005 and December 31, 2005 (a)	**Date on which director reaches age 70 (b)**
J H Bryan	5,546	October 5, 2006
E B Davis, Jr	4,490	August 5, 2014
Dr W E Massey	3,346	April 5, 2008
Director who left the board in 2006		
M H Wilson (c)	3,170	November 4, 2007

(a) No awards were granted and no awards lapsed during the year. The awards were granted over Amoco stock prior to the merger but their notional weighted average market value at the date of grant (applying the subsequent merger ratio of 0.66167 of a BP ADS for every Amoco share) was $27.87 per BP ADS.

(b) For the purposes of the regulations, the date on which the director retires from the board at or after the age of 70 is the end of the qualifying period. If the director retires prior to this date, the board may waive the restrictions.

(c) Mr Wilson resigned from the board on February 28, 2006. In accordance with the terms of the plan, the board exercised its discretion to waive the restrictions on May 11, 2006 (when BP ADS closing price was $75.52) without payment by him. These awards over BP ADSs derived from awards over Amoco shares granted between April 26, 1994 and April 28, 1998.

Superannuation Gratuities

In accordance with the Company s long-standing practice, non-executive directors who retired from the board after at least six years service are, at the time of their retirement, eligible for consideration for a superannuation gratuity. The board is authorized to make such payments under the Company s Articles. The amount of the payment is determined at the board s discretion (having regard to the director s period of service as a director and other relevant factors).

The board made superannuation gratuity payments during the year to the following former directors: Mr Knight £79,000 and Sir Robin Nicholson £84,000 (who both retired in 2005) and Mr Maljers £18,000 (who retired in 2004). These payments were in line with the policy arrangements agreed in 2002.

In May 2006, the board also approved superannuation gratuity payments to two directors, Mr Miles £46,000 and Mr Wilson £21,000, who each left the board in 2006.

In 2002, the board revised its policy with respect to superannuation gratuities so that: (i) non-executive directors appointed to the board after July 1, 2002 would not be eligible for consideration for such a payment; and (ii) while non-executive directors in service at July 1, 2002 would remain eligible for consideration for a payment, service after that date would not be taken into account by the board in considering the amount of any such payment.

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Non-Executive Directors Shareholdings

Non-Executive Directors interest in BP ordinary shares or calculated equivalents	**At January 1, 2005**	**At December 31, 2005**	**At June 28, 2006**
J H Bryan	158,760 (a)	158,760 (a)	158,760 (a)
A Burgmans	10,000	10,000	10,000
E B Davis, Jr	66,349 (a)	67,610 (a)	68,271 (a)
D J Flint		15,000	15,000
Dr D S Julius	15,000	15,000	15,000
Sir Tom McKillop	20,000	20,000	20,000
Dr W E Massey	49,722 (a)	49,722 (a)	49,722 (a)
H M P Miles (b)	22,145	22,145	22,145 (d)
Sir Ian Prosser	16,301	16,301	16,301
P D Sutherland	30,079	30,079	30,079
M H Wilson (c)	60,000 (a)	60,000 (a)	60,000 (a)(e)
Directors who left the board in 2005	At January 1, 2005	At Retirement	
C F Knight	98,578 (a)	98,782 (a)	
Sir Robin Nicholson	4,020	4,052	

(a) Held as ADSs.

(b) Retired at AGM on April 20, 2006

(c) Resigned as a Director on February 28, 2006

(d) At date of retirement.

(e) At date of resignation.

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

No director has any interest in the preference shares or debentures of the Company, or in the shares or loan stock of any subsidiary company.

Total Remuneration

Remuneration of Directors and Senior Management

The table below details remuneration of all directors and senior management as a group (21 persons at December 31, 2005).

	Year ended December 31,		
	2005	**2004**	**2003**
		($ million)	
Short-term employee benefits	25	24	20
Postretirement benefits	4	3	2
Share-based payment	27	20	20

Short-term Employee Benefits

In addition to fees paid to the non-executive chairman and non-executive directors, these amounts comprise, for executive directors and senior management, salary and benefits earned during the year, plus bonuses awarded for the year.

Postretirement Benefits

The amounts represent the estimated cost to the Group of providing pensions and other post-retirement benefits to key management in respect of the current year of service measured in accordance with IAS 19 Employee Benefits .

Share-based Payments

This is the cost to the Group of key management s participating in share-based payment plans, as measured by the fair value of options and shares granted accounted for in accordance with IFRS 2 Share-based payments . The main plans in which key management have participated are the Executive Directors Incentive Plan (EDIP) (see Compensation Policy on Executive Directors Remuneration Elements of Remuneration Long-Term Incentives in this Item on page 116), the Medium Term Performance Plan (MTPP) and the Long Term Performance Plan (LTPP) (described below).

Plans for Senior Employees

Medium Term Performance Plan (MTPP) (2005 onwards)

An equity-settled incentive share plan for senior employees driven by two performance measures over a three-year performance period. The award of shares is determined by comparing BP s TSR against the other oil majors and, additionally, by comparing free cash flow (FCF) against a threshold established for the period. For a small group of particularly senior employees, only the TSR measure is applicable in determining the award. The number of shares awarded is increased to take account of the net dividends that would have been received during the performance period, assuming that such dividends had been reinvested. With regard to leaver provisions, the general rule is that leaving employment during the performance period will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after completion of the first year of the performance period.

Long Term Performance Plan (LTPP) (pre-2005)

An equity-settled incentive share plan for senior employees driven by three performance measures over a three-year performance period. The primary measure is BP s SHRAM versus that of the companies within the FTSE All World Oil & Gas Index. This accounts for nearly two-thirds of the potential total award, with the remainder being assessed on BP s relative ROACE and EPS growth compared with the other oil majors. Shares are awarded at the end of the performance period and are then subject to a three-year restriction period. With regard to leaver provisions, the general rule is that leaving during the performance period will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after completion of the first year of the performance period. This plan was replaced by the MTPP for 2005 onwards.

Deferred Annual Bonus Plan (DAB)

An equity-settled restricted share plan for senior employees. The award value is equal to 50% of the annual cash bonus awarded for the preceding performance year (the performance period). The shares are restricted for a period of three years (the restriction period). Shares accrue dividends during the restriction period and these are reinvested. With regard to leaver provisions, if a participant ceases to be employed by BP prior to the end of the performance period, then the general rule is that this will preclude an award of shares. However, special arrangements apply where the participant leaves for a qualifying reason. Similarly, if a participant ceases to be employed by BP prior to the end of the restriction period, the general rule is that the restricted shares will be forfeited. Special arrangements apply where the participant leaves for a qualifying reason.

Restricted Share Plan (RSP)

An equity-settled restricted share plan used predominantly for senior employees in special circumstances (such as recruitment and retention). There are no performance conditions but the shares are subject to a three-year restriction period. During the restriction period, shares accrue dividends, which are reinvested. With regard to leaver provisions, the general rule is that ceasing employment during the restriction period will result in the forfeit of shares. However, special arrangements apply where the participant leaves for a qualifying reason.

BP Share Option Plan (BPSOP)

An equity-settled share option plan that applies to certain categories of employees. Participants are granted share options with an exercise price no lower than market price of a share immediately preceding the date of grant. There are no performance conditions and the options are exercisable between the third and 10th anniversaries of the grant date. The general rule is that the options will lapse if the participant leaves employment before the end of the third calendar year from the date of grant (and that vested options are exercisable within $3^1/2$ years from the date of leaving). However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after the end of the calendar year of the date of grant. Share options are no longer offered to the most senior employees.

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BOARD PRACTICES

Directors Terms of Office	Date of expiration of current term of office (a)	Period during which the director has served in this office (from appointment to June 2006)
Dr D C Allen	April 2007	3 years 4 months
The Lord Browne of Madingley	April 2007	14 years 9 months
J H Bryan (b)	April 2007	7 years 6 months
A Burgmans	April 2007	2 years 4 months
I C Conn	April 2007	1 year 11 months
E B Davis, Jr (b)	April 2007	7 years 6 months
D J Flint	April 2007	1 year 5 months
Dr B E Grote	April 2007	5 years 10 months
Dr A B Hayward	April 2007	3 years 4 months
Dr D S Julius	April 2007	4 years 7 months
Sir Tom McKillop	April 2007	1 year 11 months
J A Manzoni	April 2007	3 years 4 months
Dr W E Massey (b)	April 2007	7 years 6 months
Sir Ian Prosser	April 2007	9 years 1 month
P D Sutherland	April 2007	10 years 11 months

(a) Shareholders approved an amendment to the Articles of Association such that at each AGM held after December 31, 2004, all directors shall retire from office and may offer themselves for re-election. Therefore all directors retired and offered themselves for re-election in accordance with the Articles of Association at the 2006 AGM.

(b) Does not include service on the board of Amoco Corporation

Directors Service Contracts Providing for Benefits upon Termination of Employment

The service contracts of Dr Allen, Mr Conn, Dr Hayward and Mr Manzoni may be terminated by the Company at any time with immediate effect on payment in lieu of notice equivalent to one year s salary or the amount of salary that would have been paid if the contract had terminated on the expiry of the remainder of the notice period.

Dr Grote s service contract is with BP Exploration (Alaska) Inc. He is seconded to BP p.l.c. under a secondment agreement dated August 7, 2000 that had an unexpired term of two years at December 31, 2005. The secondment may be terminated by one month s notice by either party and terminates automatically on the termination of Dr Grote s service contract.

There are no other provisions for compensation payable on early termination of the above contracts. In the event of early termination under any of the above contracts by the Company other than for cause (or under a specific termination provision), the relevant director s then current salary and benefits would be taken into account in calculating any liability of the Company.

Since January 2003, the committee has included a provision in new service contracts to allow for severance payments to be phased, where appropriate to do so. It will also consider mitigation to reduce compensation to a departing director, where appropriate to do so.

Governance and the Role of Our Board

The governance of companies continues to be under scrutiny. Regulators and commentators maintain their focus on structural elements. We believe too little attention is paid to the underlying purpose of governance. Governance lies at the heart of all the board does and it is the task our owners entrust to the board.

Governance is not an exercise in compliance nor is it a higher form of management. Governance is a more powerful concept. It has a clear objective: ensuring the pursuit of the Company s purpose. The board s activity is focused on this task, which is unique to it as the representative of BP s owners. This task is discharged by the board through undertaking such activities as are necessary for the effective promotion of long-term shareholder interest. In promoting the long-term interest of shareholders, the board has to ensure that the business is responsive to the views of those with whom it comes into contact. This can include gaining an understanding of the environmental and social consequences of the Company s actions. However, it remains a matter of business judgement as to how these consequences are properly taken into account in maximizing shareholder value.

Governance is the system by which the Company s owners and their representatives on the board ensure that it pursues, does not deviate from and only allocates resources to its defined purpose.

As a Company, we recognize the importance of good governance and that it is a discrete task from management. Clarity of roles is key to our approach. Policies and processes depend on the people who operate them. Governance requires distinct skills and processes. Governance is overseen by the BP board, while management is delegated to the group chief executive by means of the board governance policies.

Our board governance policies use a coherent, principles-based approach, which anticipated many developments in UK governance regulation. These policies ensure that our board and management operate within a clear and efficient governance framework that places long-term shareholder interest at the heart of all we do.

To that end, our board exercises judgement in carrying out its work in policy-making, in monitoring executive action and in its active consideration of Group strategy. The board s judgements seek to maximize the expected value of shareholders interest in the Company, rather than eliminate the possibility of any adverse outcomes.

Accountability to Shareholders

Our board is accountable in a variety of ways. It is required to be proactive in obtaining an understanding of shareholder preferences and to evaluate systematically the economic, social, environmental and ethical matters that may influence or affect the interests of our shareholders.

Reporting

A number of formal communication channels are used to account to shareholders for the performance of the Company. These include the Annual Report and Accounts, the Annual Review, the Annual Report on Form 20-F, quarterly Forms 6-K and announcements made through stock exchanges on which BP shares are listed, as well as through the annual general meeting (AGM). BP is keen to promote the use of electronic platforms in the reporting arena.

Dialogue with Directors

Presentations given at appropriate intervals to representatives of the investment community are available to all shareholders by internet broadcast or open conference call, details of which are given on *www.bp.com.* Less formal processes include contacts with institutional shareholders by the chairman and other directors. This is supported by the dialogue with shareholders concerning the governance and operation of the Group maintained by the company secretary s office, investor relations and other BP teams, which meet with investors and shareholder groups representing both large and small investors.

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Our board is accountable to shareholders for the performance and activities of the entire BP Group. It embeds shareholder interest in the goals established for the Company.

AGM and Voting

The chairman and board committee chairmen were present at the 2005 and 2006 AGMs to answer shareholders questions and hear their views during the meeting. Members of the board met informally with shareholders afterwards. Given the size and geographical diversity of our shareholder base, we recognize that opportunities for shareholder interaction at the AGM are limited. However, all votes at shareholder meetings, whether by proxy or in person, are counted, since votes on all matters, except procedural issues, are taken by way of a poll. In 2005, we were pleased to note that voting levels increased to 62%, with more than 98% of votes being cast in line with the board s recommendations, a trend that continued at the 2006 AGM.

Directors Elections

Directors stand for re-election each year. New directors are subject to election at the first opportunity following their appointment. All names submitted to shareholders for election are accompanied by biographies. Voting levels demonstrate continued support for all our directors and affirm the board s assertion of the independence of all our non-executive directors.

How our Board Governs the Company

The board s governance policies outline its relationship with shareholders, the conduct of board affairs and the board s relationship with the group chief executive. The policies recognize the board s separate and unique role as the link in the chain of authority between the shareholders and the group chief executive. It is this unique task that gives the board its central role in governance.

The dual role played by the group chief executive and executive directors as both members of the board and leaders of the executive management is also recognized and addressed. The policies require a majority of the board to be composed of independent non-executive directors. To assure the integrity of the governance process, the relationship between the board and the group chief executive is governed by the non-executive directors, particularly through the work of the board committees they populate.

Recognizing that as a group its capacity is limited, our board reserves to itself the making of broad policy decisions. It delegates more detailed considerations involved in meeting its stated requirements either to board committees and officers (in the case of its own processes) or to the group chief executive (in the case of the management of the Company s business activities). The board governs BP through setting general policy for the conduct of business (and, critically, by clearly articulating its goals) and by monitoring its implementation by the group chief executive.

To discharge its governance function in the most effective manner, our board has laid down rules for its own activities in a governance process policy. The process policy covers:

- The conduct of members at meetings.
- The cycle of board activities and the setting of agendas.
- The provision of timely information to the board.
- Board officers and their roles.
- Board committees their tasks and composition.
- Qualifications for board membership and the process of the nomination committee.
- The evaluation and assessment of board performance.
- The remuneration of non-executive directors.

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The process for directors to obtain independent advice.

The appointment and role of the company secretary.

The responsibility for implementation of this policy is placed on the chairman.

The board-executive linkage policy sets out how the board delegates authority to the group chief executive and the extent of that authority. In its board goals policy, the board states what it expects the group chief executive to deliver.

The restrictions on the manner in which the group chief executive may achieve the required results are set out in the executive limitations policy. This policy sets boundaries on executive action, requiring due consideration of internal controls, risk preferences, financing, ethical behaviour, health, safety, the environment, treatment of employees and political considerations in any and all action taken in the course of our business. Through the goals and executive limitations policies, the board shapes BP s values and standards.

Accountability in our Business

Our group chief executive outlines how he intends to deliver the required outcome in annual and medium-term plans, which also address a comprehensive assessment of the Group s risks. Progress towards the expected outcome forms the basis of regular reports to the board that cover actual results and a forecast of results for the current year. The board considers annual and five-year plans for the Group and, in doing so, reviews the major influences and risks affecting the Group s business.

The group chief executive is obliged through dialogue and systematic review to discuss with the board all material matters currently or prospectively affecting the Company and its performance and all strategic projects or developments. This key dialogue specifically includes any materially under-performing business activities and actions that breach the executive limitations policy and material matters of a social, environmental and ethical nature.

The board-executive linkage policy also sets out how the group chief executive s performance will be monitored and recognizes that, in the multitude of changing circumstances, judgement is always involved. The systems set out in the board-executive linkage policy are designed to manage, rather than to eliminate, the risk of failure to achieve the goals or observe the executive limitations policy. They provide reasonable, not absolute, assurance against material misstatement or loss.

Who is on the Board?

The board is composed of nine non-executive directors, including the chairman and six executive directors. In total, four nationalities are represented on the board. Directors biographies are set out in this Item Directors, Senior Management and Employees Directors and Senior Management on page 112.

Governance policies and processes depend on the quality and commitment of the people who operate them.

As reported last year, the board is actively engaged in succession planning issues for both executive and non-executive roles. We reported in the past two years on our pursuit of an orderly process of evolution to refresh the composition of the board without compromising its continued effectiveness. To that end, we were delighted to welcome Mr Douglas Flint to the board in January 2005. At the AGM in April 2005, Sir Robin Nicholson and Mr Charles (Chuck) Knight retired and Mr Michael Miles stood down at the 2006 AGM. The chairmanships of the principal board committees were also reviewed during 2005; Dr Julius became chairman of the remuneration committee, succeeding Sir Robin Nicholson. The board committee reports in Board Practices Board Committees in this Item on page 138 provide details on the chairmen and composition of these committees.

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The efficiency and effectiveness of the board are of paramount importance. Our board is large but this is necessary to allow sufficient executive director representation to cover the breadth of the Group s business activities and sufficient non-executive representation to reflect the scale and complexity of BP and to staff our board committees. A board of this size allows orderly succession planning for key roles.

Board Independence

The qualification for board membership includes a requirement that all our non-executive directors be free from any relationship with the executive management of the Company that could materially interfere with the exercise of their independent judgement. In the board s view, all our non-executive directors fulfil this requirement. It determined all non-executive directors who served during 2005 to be independent. All have received overwhelming endorsement at successive AGMs, at which they are now subject to annual election.

Mr Knight and Sir Robin Nicholson were appointed to the BP board in 1987 and Mr Miles was appointed in 1994. The length of their respective service on the board exceeds the nine years referred to in the Combined Code. The board considers that the experience and long-term perspective of each of these directors on BP s business during its recent period of growth has provided a valuable contribution to the board, given the long-term nature of our business. The integrity and independence of character of these directors are beyond doubt. Both Mr Knight and Sir Robin retired at the 2005 AGM and Mr Miles retired at the 2006 AGM.

Those directors who joined the BP board in 1998 after service on the board of Amoco Corporation (Messrs Bryan, Massey, Wilson and Davis) are considered independent since the most senior executive management of BP comprises individuals who were not previously Amoco employees. While Amoco businesses and assets are a key part of the Group, the scope and scale of BP since its acquisition of the ARCO, Burmah Castrol and Veba businesses are fundamentally different from those of the former Amoco Corporation.

Annual elections for all directors and the provision of independent support to our board and board committees underscore our commitment to good governance practice.

The board has satisfied itself that there is no compromise to the independence of those directors who serve together as directors on the boards of outside entities (or who have other appointments in outside entities). Where necessary, our board ensures appropriate processes are in place to manage any possible conflict of interest.

Sir Robin Nicholson received fees during 2005 for representing the board on the BP technology advisory council. Since these fees relate to board representation, they did not compromise Sir Robin s independence. Full details of these fees are disclosed in Compensation Remuneration of Non-Executive Directors in this Item on page 127.

Directors Appointments, Retirement Policies and Insurance

The chairman and non-executive directors of BP are elected each year and, subject to BP s Articles of Association, serve on the basis of letters of appointment. Executive directors of BP have service contracts with the Company. Details of all payments to directors are set out in Compensation in this Item on pages 115-131.

BP s policy on directors retirement is as follows: executive directors retire at age 60, while non-executive directors ordinarily retire at the AGM following their 70th birthday. It is the board s policy that non-executive directors are not generally expected to hold office for more than 10 years.

In accordance with BP s Articles of Association, directors are granted an indemnity from the Company in respect of liabilities incurred as a result of their office, to the extent permitted by law. In respect of those liabilities for which directors may not be indemnified, the Company purchased and maintained a directors and officers liability insurance policy throughout 2005. This insurance cover was renewed at the beginning of 2006. Although their defence costs may be met, neither the Company s indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly.

Board and Committees: Meetings and Attendance

In addition to the 2005 AGM (which 17 directors attended), the board met seven times during 2005: four times in the UK, twice in the US and once in China. Two of these meetings were two-day strategy discussions. 2005 saw a continued high number of committee meetings, a trend we expect to continue.

The board requires all members to devote sufficient time to the work of the board to discharge the office of director and to use their best endeavours to attend meetings.

Serving as a Director: Induction, Training and Evaluation

Induction

Directors receive induction on their appointment to the board as appropriate, covering matters such as the operation and activities of the Group (including key financial, business, social and environmental risks to the Group s activities), the role of the board and the matters reserved for its decision, the tasks and membership of the principal board committees, the powers delegated to those committees, the board s governance policies and practices, and the latest financial information about the Group. The chairman is accountable for the induction of new board members.

Training

Our directors are updated on BP s business, the environment in which it operates and other matters throughout their period in office. Our directors are advised on their appointment of the legal and other duties and obligations they have as directors of a listed company. The board regularly considers the implications of these duties under the board governance policies. Our non-executive directors also receive training specific to the tasks of the particular board committees on which they serve.

Outside Appointments

As part of their ongoing development, our executive directors are permitted to take up an external board appointment, subject to the agreement of our board. Executive directors retain any fees received in respect of such external appointments. Generally, outside appointments for executive directors are limited to one outside company board only, although our group chief executive, by exception, serves on two outside company boards. Our board is satisfied that these appointments do not conflict with his duties and commitment to BP. Non-executive directors may serve on a number of outside boards, always provided they continue to demonstrate the requisite commitment to discharge effectively their duties to BP. The nomination committee keeps the extent of directors other interests under review to ensure that the effectiveness of our board is not compromised.

Evaluation

The board continued its ongoing evaluation processes to assess its performance and identify areas in which its effectiveness, policies or processes might be enhanced. A formal evaluation of board process and effectiveness was undertaken, drawing on internal resources. Individual questionnaires and interviews were completed; no individual performance problems were identified. The results showed an improvement from the previous evaluation, particularly in board committee process and activities, while also identifying areas for further improvement.

Regular evaluation of board effectiveness underpins our confidence in BP s governance policies and processes and affords opportunity for their development.

Separate evaluations of the remuneration, ethics and environment and audit assurance committees took place during the year. The use of external providers in the context of board evaluation is being kept under review.

The Chairman and Senior Independent Director

BP s board governance policies require that neither the chairman nor deputy chairman are to be employed executives of the Group; throughout 2005 the posts were held by Mr Sutherland and Sir Ian Prosser respectively. Sir Ian also acts as our senior independent director and is the director whom shareholders may contact if they feel their concerns are not being addressed through normal channels.

Between board meetings, the chairman has responsibility for ensuring the integrity and effectiveness of the board/executive relationship. This requires his interaction with the group chief executive between board meetings, as well as his contact with other board members and shareholders. The chairman represents the views of the board to shareholders on key issues, not least in succession planning issues for both executive and non-executive appointments. The chairman and all the non-executive directors meet periodically as the chairman s committee (see Board Practices Board Committees in this Item on page 138). The performance of the chairman is evaluated each year at a meeting of the chairman s committee, for which item of business he is not present. The company secretary reports to the chairman and has no executive functions.

Board Committees

The governance process policy allocates the tasks of monitoring executive actions and assessing performance to certain board committees. These tasks, rather than any terms of reference, prescribe the authority and the role of the board committees. Reports for each of the committees for 2005 appear below. In common with the board, each committee has access to independent advice and counsel as required and each is supported by the company secretary s office, which is demonstrably independent of the executive management of the Group.

Audit Committee Report

Schedule and Composition

The committee met 12 times during 2005 and comprised the following directors: Sir Ian Prosser (chairman), J H Bryan, E B Davis, Jr, D J Flint, H M P Miles, M H Wilson.

All members of the audit committee are non-executive directors whom the board has determined to be independent and who meet the requirements of the UK Combined Code and Rule 10A-3 of the US Securities Exchange Act of 1934. Together, the audit committee members continue to have the recent and relevant financial experience required to discharge the committee s duties. Following his appointment to the committee this year, the board satisfied itself that Mr Flint as an individual possesses the financial experience identified in the UK Combined Code guidance and may be regarded as an audit committee financial expert as defined for purposes of disclosure in Item 16A of Form 20-F. See Item 16A Audit Committee Financial Expert on page 174.

The external auditors lead partner, the BP general auditor (head of internal audit), together with the group chief financial officer, the chief accounting officer and the group controller, attend each meeting at the request of the committee chairman. During the year, the committee meets with the external auditor, without the executive management being present, and also meets in private session with the BP general auditor.

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Role and Authority

The audit committee s tasks are considered by the committee to be broader than those envisaged under Combined Code Provision C.3.2. The committee is satisfied that it addresses each of those matters identified as properly falling within an audit committee s purview. The committee has full delegated authority from the board to address those tasks assigned to it. In common with the board and all committees, it may request any information from the executive management necessary to discharge its functions and may, where it considers it necessary, seek independent advice and counsel.

Process

The committee structures its work programme so as to discharge its tasks, which include systematic monitoring and obtaining assurance that the legally required standards of disclosure are being fully and fairly observed and that the executive limitations relating to financial matters are being observed. Forward agendas are set each year to meet these requirements and to allow the committee to monitor (and seek assurance on) the management of the financial risks identified in the Company s annual business plan. The committee chairman reports on the committee s activities to the board meeting immediately following a committee meeting. Between meetings, the committee chairman reviews emerging issues as appropriate with the group chief financial officer, the external auditor and the BP general auditor. He is supported in this task by the company secretary s office. During the year, external specialist legal and regulatory advice has also been provided to the committee by Sullivan & Cromwell LLP.

Activities in 2005

Financial Reports

During the year, the committee reviewed all annual and quarterly financial reports before recommending their publication on behalf of the board. In particular, the committee reviewed the implementation of International Financial Reporting Standards and their impact on the Group s financial results and the restatement of comparative information. The committee discussed and constructively challenged judgements related to critical accounting policies and estimates drawing on prepared reports, presentations and independent advice from the external auditors.

Internal Control and Risk Management

During the year, specific reports on risk management and internal control were reviewed for the Exploration and Production, Refining and Marketing, and Gas, Power and Renewables segments, along with the controls and systems underpinning the trading functions that service all BP s businesses. Reviews were undertaken of the reporting interface between the Group and TNK-BP and of the planned disposal of the Innovene petrochemicals business. On a quarterly basis, the committee also monitored the Company s progress in evaluating its internal controls in response to applicable requirements of Section 404 of the US Sarbanes-Oxley Act of 2002. Regular advice was also provided by the internal audit function, including an annual assessment of the effectiveness of the Company s enterprise level controls.

Special topics considered during the year included capital project selection processes, the assessment of environmental and litigation provisions and accounting for long-term contractual commitments.

Employee Concerns Reporting/Whistleblowing

The committee received regular reports of the matters raised through the employee concerns programme, OpenTalk, and, through this process, together with the receipt of quarterly fraud reports from internal audit, was alerted to instances of actual or potential concern related to the finances and financial accounting of the Group.

External Auditors

In addition to the lead partner s attendance at all meetings, the committee regularly invited other relevant audit partners to participate during business segment reviews. Private meetings were held without executive management present.

The committee evaluated the performance of the external auditors and enquired into their independence, objectivity and viability. Independence was safeguarded by limiting non-audit services provided by the auditor to defined audit-related work and tax services that fall within specific categories. All such services were pre-approved by the committee and monitored quarterly. A new lead audit partner is appointed every five years, with other senior audit staff rotating every seven years; no senior staff connected with the BP audit may transfer to the Company.

After review of the audit engagement terms and proposed fees, the committee advised the board of its assessment and recommended that reappointment of the auditors be proposed at the AGM. Their reappointment was duly approved by shareholders at the AGM on April 14, 2005, and at the Company s most recent AGM on April 20, 2006.

Internal Audit

The committee agreed with the BP general auditor the programme to be undertaken during the year and the resources required. Twice-yearly reports of audit findings and management responses were reviewed in detail. Discussions of these reports contributed to the committee s view of the effectiveness of the Company s system of internal controls and hence its advice to the board on this matter. The committee also met privately with the BP general auditor, without the presence of executive management, and evaluated the performance of the function.

Performance Evaluation

On an annual basis, the committee conducts a review of its process and performance. The form of review varies to encourage fresh thinking and this year involved face-to-face interviews with individual members and with others in regular attendance. Outcomes were discussed at the committee s November meeting. The committee concluded that few substantive changes were required but used the discussion to help shape the 2006 forward agenda and in particular to increase the frequency of the committee s private meetings.

Ethics and Environment Assurance Committee Report

Schedule and Composition

The committee met seven times during 2005 and comprised the following directors: Dr W E Massey (chairman), A Burgmans, H M P Miles, M H Wilson. Sir Tom McKillop joined the committee in May 2006, following the departures of Mr Miles and Mr Wilson.

All members of the ethics and environment assurance committee are independent non-executive directors. The external auditors lead partner and the BP general auditor (head of internal audit) attend each meeting at the request of the committee chairman.

Role and Authority

The task of the committee is to monitor on behalf of the board matters relating to the executive management s processes to address environmental, health and safety, security and ethical behaviour issues. The committee monitors the observance of the executive limitations relating to nonfinancial risks to the Group. Just as for the audit committee, it has the right to request any information from the executive management that it considers necessary to discharge its functions. The committee chairman reports on the committee s activities to the board meeting immediately following a committee meeting.

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Process and Activities in 2005

This committee has a broad remit because it covers all nonfinancial risks and must necessarily be selective in setting its agendas. These are focused on regular reports such as health, safety and environment (HSE) reviews and compliance and ethics certification reports that allow the committee to monitor and assess the observance of the executive limitations. In addition, the committee reviews specific risks that are identified in the Company s annual plan and developments in business and functional areas that may emerge during the year. During 2005, the committee met specially to consider the incident at the Texas City refinery. It reviewed the causes of the accident and the implications for the Group of the lessons to be learned. The committee continues to monitor the executive management s response and the strengthening of its safety and operational capability.

Other areas of specific focus during the year included:

Business Continuity and Crisis Management

The committee received reports and reviewed the Group s enhanced focus on bringing more consistency and resilience to these linked topics across all business segments and functions.

Health, Safety and Environmental Performance

While overshadowed by events at Texas City, the progress in addressing road safety, employee health, greenhouse gas emissions, oil spills and plant integrity was considered during 2005. Specific attention was given to the progress made by TNK-BP in improving HSE standards in its operations in Russia.

Regional Reviews

Most board-level monitoring is conducted through a business segment or functional dimension, but the committee also examines risks that require management at regional or country level. In 2005, risk reviews were undertaken for Africa, the Middle East and Alaska.

Digital Security

The committee considered the Company s response to the increasing international threats to communications and computing, threats heightened by the convergence and increased interconnectivity of technology infrastructure.

Remuneration Committee

Schedule and Composition

The committee members are all non-executive directors. Dr Julius (chairman), Mr Bryan, Mr Davis, Sir Tom McKillop and Sir Ian Prosser were members of the committee throughout the year. Sir Robin Nicholson and Mr Knight retired from the committee at the 2005 AGM. Each member is now subject to annual re-election as a director of the Company. The board has determined all committee members to be independent. They have no personal financial interest, other than as shareholders, in the committee s decisions. The committee met six times in the period under review. There was a full attendance record, except for Mr Davis and Sir Robin Nicholson who were each unable to attend one meeting and Mr Knight who was unable to attend two meetings. Mr Sutherland, as chairman of the board, attended all committee meetings.

The committee is accountable to shareholders through its annual report on executive directors remuneration. It will consider the outcome of the vote at the AGM on the directors remuneration report and take into account the views of shareholders in its future decisions. The committee values its dialogue with major shareholders on remuneration matters.

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Advice

Advice is provided to the committee by the company secretary s office, which is independent of executive management and reports to the chairman of the board. Mr Aronson, an independent consultant, is the committee s secretary and special adviser. Advice was also received from Mr Jackson (company secretary) and Mrs Martin (senior counsel, company secretary s office).

The committee also appoints external professional advisers to provide specialist advice and services on particular remuneration matters. The independence of advice is subject to annual review.

The committee continued the engagement of Towers Perrin as its principal external adviser during 2005. Towers Perrin also provided limited ad hoc remuneration and benefits advice to parts of the Group, mainly comprising pensions advice in Canada, as well as providing some market information on pay structures. The committee also continued the engagement of Kepler Associates to advise on performance measurement. Kepler Associates also provided performance data and limited ad hoc advice on performance measurement to the Group.

Freshfields Bruckhaus Deringer provided legal advice on specific matters to the committee as well as providing some legal advice to the Group.

Ernst & Young reviewed the calculations in respect of financial-based targets that form the basis of the performance-related pay for the executive directors.

Lord Browne (group chief executive) was consulted on matters relating to the other executive directors who report to him and on matters relating to the performance of the Company. He was not present when matters affecting his own remuneration were considered.

Role and Authority

The committee s tasks are:

To determine, on behalf of the board, the terms of engagement and remuneration of the group chief executive and the executive directors and to report on those to the shareholders.

To determine, on behalf of the board, matters of policy over which the Company has authority relating to the establishment or operation of the Company s pension scheme of which the executive directors are members.

To nominate, on behalf of the board, any trustees (or directors of corporate trustees) of such scheme.

To monitor the policies being applied by the group chief executive in remunerating senior executives other than executive directors.

Remuneration Committee Report

Full details of executive directors remuneration is set out under Compensation in this Item on pages 115-131.

Chairman s Committee report

Schedule and Composition

The chairman s committee met four times during 2005 and comprised all the non-executive directors.

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Role and Authority

The task of the committee is to consider broad issues of governance, including the performance of the chairman and the group chief executive, succession planning, the organization of the Group and any matters referred to it for an opinion from another board committee.

Process and Activities in 2005

At its various meetings, the committee evaluated the performance of the chairman and the group chief executive, considered the plan for executive succession and considered a number of other broad matters of governance, including issues that spanned the remit of the other principal committees. Additionally, the committee addressed non-executive succession planning issues in co-ordination with the nomination committee.

Nomination Committee Report

Schedule and Composition

The committee met twice during 2005 and comprised the following directors: P D Sutherland (chairman), Dr D S Julius (from the 2005 AGM), Dr W E Massey, Sir Robin Nicholson (retired at the 2005 AGM), Sir Ian Prosser. All members of the nomination committee have been determined by the board to be independent.

Role and Authority

The task of the nomination committee is to identify and evaluate candidates for appointment and reappointment as director or company secretary of BP.

Process

During the year, the nomination committee carried out a detailed review of the skills and expertise of the non-executive directors as part of the board succession planning described earlier. The committee receives external assistance as required. The committee consults with the group chief executive concerning the identification and appointment of new executive directors. External search consultants are retained in the UK/ Europe and in the US to assist the committee to identify potential candidates as non-executive directors.

Activities in 2005

The committee considered the composition of the board and board committees in the context of forthcoming work programmes, BP s strategy and business activities and retirements from the board. In its succession planning for both executive and nonexecutive directors, the committee is mindful of the requirements of the Group s strategy and five-year plan. Board and committee evaluation processes informed its work in identifying the skills and experiences sought from potential candidates. Evaluations of the balance of skills and experience on the board are carried out in conjunction with the chairman s committee. The committee keeps under review contingency planning for key executive and non-executive director roles. The nomination committee recommended to the board that 17 incumbent directors be proposed for re-election at the AGM.

All directors recommended for re-election were subsequently elected by shareholders at the 2005 AGM. All directors, save Mr Wilson, who resigned from the board on February 28, 2006, stood for election at the 2006 AGM and were re-elected by shareholders.

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EMPLOYEES

	UK	Rest of Europe	USA	Rest of World	Total
Number of employees at December 31, 2005					
Exploration and Production	3,100	700	5,600	7,600	17,000
Refining and Marketing	11,300	19,700	25,200	14,600	70,800
Gas, Power and Renewables	200	700	1,500	1,700	4,100
Other businesses and corporate	1,900	200	2,100	100	4,300
	16,500	21,300	34,400	24,000	96,200
2004					
Exploration and Production	2,900	600	5,000	7,100	15,600
Refining and Marketing	10,400	19,500	26,500	13,400	69,800
Gas, Power and Renewables	200	800	1,400	1,600	4,000
Other businesses and corporate	4,000	5,000	4,000	500	13,500
	17,500	25,900	36,900	22,600	102,900
2003					
Exploration and Production	3,000	700	4,600	6,800	15,100
Refining and Marketing	10,300	18,800	27,000	12,900	69,000
Gas, Power and Renewables	200	800	1,400	1,400	3,800
Other businesses and corporate	3,600	5,000	6,100	1,100	15,800
	17,100	25,300	39,100	22,200	103,700

Employee numbers decreased in 2005 compared with 2004 primarily due to the sale of Innovene.
The Company seeks to maintain constructive relationships with labour unions.

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SHARE OWNERSHIP

Directors and Senior Management

As at June 28, 2006, the following directors of BP p.l.c. held interests in BP ordinary shares of 25 cents each or their calculated equivalent as set out below:

Dr D C Allen	530,933	819,823 (b)
The Lord Browne of Madingley	2,522,840	3,768,016 (b)
I C Conn	206,642	799,032 (b)
Dr B E Grote	1,092,292	972,210 (b)
Dr A B Hayward	399,466	819,823 (b)
J A Manzoni	369,191	819,823 (b)
J H Bryan	158,760	
A Burgmans	10,000	
E B Davis, Jr	68,271	
D J Flint	15,000	
Dr D S Julius	15,000	
Dr W E Massey	49,722	
Sir Tom McKillop	20,000	
Sir Ian Prosser	16,301	
P D Sutherland	30,079	

As at June 28, 2006, the following directors of BP p.l.c. held options under the BP Group share option schemes for ordinary shares or their calculated equivalent as set out below:

Dr D C Allen	794,950
The Lord Browne of Madingley	3,261,104
I C Conn	332,390
Dr B E Grote	1,427,190 (a)
Dr A B Hayward	769,702
J A Manzoni	780,523

(a) In addition to the above, Dr Grote holds 40,000 Stock Appreciation Rights (equivalent to 240,000 ordinary shares).

(b) Performance shares awarded under the BP Executive Directors Incentive Plan. These represent the maximum possible vesting levels. The actual number of shares/ ADSs which vest will depend on the extent to which performance conditions have been satisfied over a three year period.

There are no directors or members of senior management who own more than 1% of the ordinary Shares outstanding. At June 28, 2006, all directors and senior management as a group held interests in 14,978,547 ordinary shares or their calculated equivalent and 8,541,794 options for ordinary shares or their calculated equivalent under the BP Group share options schemes.

Additional details regarding the options granted, including exercise price and expiry dates, are found in this item under the heading Compensation Share Options.

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Employee Share Plans

	Year ended December 31,		
	2005	**2004**	**2003**
	(options thousands)		
Employee share options granted during the year (a)	54,482	80,394	104,759

(a) As share options are exercised continuously throughout the year, the weighted average share price during the year of $10.77 (2004 $8.95 and 2003 $6.81) is representative of the weighted average share price at the date of exercise. For the options outstanding at December 31, 2005, the exercise price ranges and weighted average remaining contractual lives are shown below.

BP offers most of its employees the opportunity to acquire a shareholding in the Company through savings-related and/or matching share plan arrangements. BP also uses long-term performance plans (see Item 18 Financial Statements 18 Note 46 on page F-133) and the granting of share options as elements of remuneration for executive directors and senior employees.

Savings and Matching Plans

BP ShareSave Plan

A savings-related share option plan, under which employees save on a monthly basis, over a three- or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and options are granted annually, usually in June. Until 2003, a three-year savings plan was also run in a small number of other countries. Options will remain outstanding in respect of these countries until the end of June 2007. Participants leaving for a qualifying reason will have six months in which to use their savings to exercise their options on a pro-rated basis.

BP ShareMatch Plans

Matching share plans, under which BP matches employees own contributions of shares up to a predetermined limit. The plans are run in the UK and in over 70 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. In other countries, the plan is run on an annual basis with shares being held in trust for three years. The plan is operated on a cash basis in those countries where there are regulatory restrictions preventing the holding of BP shares. When the employee leaves BP, all shares must be removed from trust and units under the plan operated on a cash basis must be encashed.

Cash Plans

Cash Options/ Stock Appreciation Rights (SARs)

These are cash-settled share-based payments available to certain employees that require the Group to pay the intrinsic value of the cash option/ SAR to the employee at the date of exercise. There are no performance conditions; however, participants must continue in employment with BP for the first three calendar years of the plan for the options/ SARs to vest. Special arrangements may apply for qualifying leavers. The options/ SARs are exercisable between the third and 10th anniversaries of the grant date.

Employee Share Ownership Plans (ESOP)

ESOPs have been established to acquire BP shares to satisfy any awards made to participants under EDIP, LTPP, MTPP, DAB and the BP ShareMatch Plans. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the Group. Until such time as the Company s own shares held by the ESOP trusts vest unconditionally in employees, the amount paid for those shares is

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deducted in arriving at shareholders equity. See Item 18 Financial Statements Note 46 on page F-133. Assets and liabilities of the ESOPs are recognized as assets and liabilities of the Group.

At December 31, 2005, the ESOPs held 14,560,003 shares (2004 8,621,219 shares and 2003 11,930,379 shares) for potential future awards, which had a market value of $156 million (2004 $84 million and 2003 $96 million).

Pursuant to the various BP Group share option schemes, the following options for ordinary shares of the Company were outstanding at June 28, 2006:

Options outstanding (shares)	Expiry dates of options	Exercise price per share
436,611,636	2006-2016	$4.31-$11.92

Further details on share options appear in Item 18 Financial Statements Note 46 on page F-133.

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ITEM 7 MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

MAJOR SHAREHOLDERS

At June 28, 2006, the Company has been notified that JPMorgan Chase Bank, as depositary for American Depositary Shares (ADSs), holds interests through its nominee, Guaranty Nominees Limited, in 6,187,041,879 ordinary shares (30.92% of the Company s ordinary share capital). Legal and General plc hold interests in 698,383,277 ordinary shares (3.49% of the Company s share capital).

At the date of this report the Company has also been notified of the following interests in preference shares. Co-operative Insurance Society Limited holds interests in 1,572,538 8% cumulative first preference shares (21.74% of that class) and 1,789,796 9% cumulative second preference shares (32.70% of that class). The National Farmers Union Mutual Insurance Society Ltd holds 945,000 8% cumulative first preference shares (13.07% of that class) and 987,000 9% cumulative second preference shares (18.03% of that class). Prudential plc holds interests in 528,150 8% cumulative first preference shares (7.30% of that class) and 644,450 9% cumulative second preference shares (11.77% of that class). Royal & SunAlliance Insurance plc holds interests in 287,500 8% cumulative first preference shares (3.97% of that class) and 250,000 9% cumulative second preference shares (4.57% of that class). Ruffer Limited Liability Partnership holds interests in 685,000 9% preference shares (12.51% of that class).

RELATED PARTY TRANSACTIONS

The Group had no material transactions with joint ventures and associated undertakings during the period commencing January 1, 2005 to the date of this filing. Transactions between the Group and its significant joint ventures and associates are summarized in Item 18 Financial Statements Note 30 on page F-75 and Item 18 Financial Statements Note 31 on page F-78.

In the ordinary course of its business the Group has transactions with various organizations with which certain of its directors are associated but, except as described in this report, no material transactions responsive to this item have been entered into in the period commencing January 1, 2005 to June 28, 2006.

ITEM 8 FINANCIAL INFORMATION

CONSOLIDATED STATEMENTS AND OTHER FINANCIAL INFORMATION

Financial Statements

See Item 18 Financial Statements.

Dividends

The total dividends announced and paid in 2005 were $7,359 million, compared with $6,041 million in 2004 and $5,654 million in 2003. Dividends per share for 2005 were 34.85 cents, compared with 27.70 cents per share in 2004 (an increase of 26%) and 25.50 cents per share in 2003 (an increase of 8.6% over 2003). For information on our policy on distributions to shareholders, refer to Item 5 Operating and Financial Review Liquidity and Capital Resources Dividends and Other Distributions to Shareholders and Gearing on page 95.

Legal Proceedings

Save as disclosed in the following paragraphs, no member of the Group is a party to, and no property of a member of the Group is subject to, any pending legal proceedings which are significant to the Group.

On June 28, 2006, the U.S. Commodity Futures Trading Commission (CFTC) announced the filing of a civil enforcement action in the United States District Court for the Northern District of Illinois

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against BP Products North America, Inc. (BP Products), a wholly owned subsidiary of BP, alleging that BP Products manipulated the price of February 2004 TET physical propane. The CFTC also charges BP Products with attempting to manipulate the price of April 2003 TET physical propane. The CFTC is seeking permanent injunctive relief, disgorgement, restitution, and payment of civil monetary penalties. Concurrently, the U.S. Department of Justice filed a criminal complaint against a former BP Products employee, who entered a guilty plea. The former employee had previously been terminated by BP Products for failure to adhere to BP Group policies. BP denies that BP Products engaged in market manipulation and intends to defend the CFTC claims vigorously. BP believes that it has cooperated fully with the CFTC in its investigation of this matter and intends to assist the Department of Justice in its ongoing investigation.

On March 23, 2005, an explosion and fire occurred in the Isomerization Unit of BP Products Texas City refinery as the unit was coming out of planned maintenance. Fifteen contractors died in the incident and many others were injured. In 2005, BP Products finalized, or is currently in process of negotiating, settlements in respect of fatalities and personal injury claims arising from the incident. The first trial of the unresolved claims is scheduled for September, 2006. The US Occupational Safety and Health Administration (OSHA), the US Chemical Safety and Hazard Investigation Board (CSB), the US Environmental Protection Agency and the Texas Commission on Environmental Quality, among other agencies, have conducted or are conducting investigations. At the conclusion of their investigation, OSHA issued citations alleging more than 300 violations of 13 different OSHA standards, and BP Products agreed not to contest the citations. BP Products settled that matter with OSHA on September 22, 2005, paying a $21.3 million penalty and undertaking a number of corrective actions designed to make the refinery safer. OSHA referred the matter to the US Department of Justice for criminal investigation, and the Department of Justice has opened an investigation. At the recommendation of the CSB, BP appointed an independent safety panel, the BP US Refineries Independent Safety Review Panel, under the chairmanship of James A Baker III. Other government legal actions are pending.

Approximately 200 lawsuits were filed in State and Federal Courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies which own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 47% interest (reduced during 2001 from 50% by a sale of 3% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP s combination with Atlantic Richfield. Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages which it has incurred. If any claims are asserted by Exxon which affect Alyeska and its owners, BP will defend the claims vigorously.

Since 1987, Atlantic Richfield Company, a current subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the United States alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed as against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting and Refining which, along with a predecessor company, manufactured lead pigment during the period 1920-1946. Plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits (depending on plaintiff) seek various remedies including: compensation to lead-poisoned children; cost to find and remove lead paint from buildings; medical monitoring and screening programmes; public warning and education of lead hazards; reimbursement of government healthcare costs and special education for lead-poisoned citizens; and punitive damages. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgement in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defenses and it intends to defend such actions vigorously and thus the incurrence of liability by Atlantic Richfield is remote. Consequently, BP believes that the impact of these lawsuits on the Group s results of operations, financial position or liquidity will not be material.

For certain information regarding environmental proceedings see Item 4 Environmental Protection United States Regional Review on page 71.

SIGNIFICANT CHANGES

None.

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ITEM 9 THE OFFER AND LISTING

Markets and Market Prices

The primary market for BP s ordinary shares is the London Stock Exchange (LSE). BP s ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index. BP s ordinary shares are also traded on stock exchanges in France, Germany, Japan and Switzerland.

Trading of BP s shares on the LSE is primarily through the use of the Stock Exchange Electronic Trading Service (SETS), introduced in 1997 for the largest companies in terms of market capitalization whose primary listing is the LSE. Under SETS, buy and sell orders at specific prices may be sent to the exchange electronically by any firm which is a member of the LSE, on behalf of a client or on behalf of itself acting as a principal. The orders are then anonymously displayed in the order book. When there is a match on a buy and a sell order, the trade is executed and automatically reported to the LSE. Trading is continuous from 8:00 a.m. to 4:30 p.m. UK time, but in the event of a 20% movement in the share price either way the LSE may impose a temporary halt in the trading of that company s shares in the order book, to allow the market to re-establish equilibrium. Dealings in ordinary shares may also take place between an investor and a market-maker, via a member firm, outside the electronic order book.

In the United States and Canada the Company s securities are traded in the form of ADSs, for which JPMorgan Chase Bank is the depositary (the Depositary) and transfer agent. The Depositary s address is 1 Chase Manhattan Plaza, 40th Floor, New York, NY 10081, USA. Each ADS represents six ordinary shares. ADSs are listed on the New York Stock Exchange, and are also traded on the Chicago, Pacific and Toronto Stock Exchanges. ADSs are evidenced by American Depositary Receipts, or ADRs, which may be issued in either certificated or book entry form.

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The following table sets forth for the periods indicated the highest and lowest middle market quotations for the ordinary shares of BP p.l.c. for the periods shown. These are derived from the Daily Official List of the LSE, and the highest and lowest sales prices of ADSs as reported on the New York Stock Exchange composite tape.

		Ordinary shares		American Depositary Shares (a)	
		High	**Low**	**High**	**Low**
		(Pence)		(Dollars)	
Year ended December 31,					
2001		647.00	478.00	55.20	42.20
2002		625.00	387.00	53.98	36.25
2003		458.00	348.75	49.59	34.67
2004		561.00	407.75	62.10	46.65
2005		686.00	499.00	72.75	56.60
Year ended December 31,					
2004:	First quarter	465.75	407.75	51.48	46.65
	Second quarter	508.25	451.25	54.99	50.75
	Third quarter	545.00	476.25	59.04	51.95
	Fourth quarter	561.00	497.00	62.10	57.31
2005:	First quarter	579.50	499.00	66.65	56.60
	Second quarter	600.00	516.00	64.94	57.95
	Third quarter	686.00	580.50	72.75	62.84
	Fourth quarter	679.00	599.00	71.25	63.26
2006:	First quarter	693.00	623.00	72.88	65.35
	Second quarter (through June 28)	723.00	581.00	76.85	64.19
Month of					
December 2005		667.00	610.50	69.25	63.26
January 2006		693.00	623.00	72.88	65.47
February 2006		677.50	630.00	72.58	66.01
March 2006		676.50	627.00	70.68	65.35
April 2006		723.00	662.00	76.85	69.49
May 2006		693.50	606.50	76.67	68.50
June (through June 28)		643.50	581.00	72.38	64.19

(a) An ADS is equivalent to six ordinary shares.

Market prices for the ordinary shares on the LSE and in after-hours trading off the LSE, in each case while the New York Stock Exchange is open, and the market prices for ADSs on the New York Stock Exchange and other North American stock exchanges, are closely related due to arbitrage among the various markets, although differences may exist from time to time due to various factors including UK stamp duty reserve tax. Trading in ADSs began on the LSE on August 3, 1987.

On June 28, 2006, 1,031,125,732 ADSs (equivalent to 6,186,754,395 ordinary shares or some 30.92% of the total) were outstanding and were held by approximately 153,236 ADR holders. Of these, about 151,659 had registered addresses in the USA at that date. One of the registered holders of ADSs represents some 850,381 underlying holders.

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On June 28, 2006, there were approximately 329,764 holders of record of ordinary shares. Of these holders, around 1,458 had registered addresses in the USA and held a total of some 4,068,149 ordinary shares.

Since certain of the ordinary shares and ADSs were held by brokers and other nominees, the number of holders of record in the USA may not be representative of the number of beneficial holders or of their country of residence.

ITEM 10 ADDITIONAL INFORMATION

MEMORANDUM AND ARTICLES OF ASSOCIATION

The following summarizes certain provisions of BP s Memorandum and Articles of Association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act and BP s Memorandum and Articles of Association. Information on where investors can obtain copies of the Memorandum and Articles of Association is described under the heading Documents on Display under this Item.

On April 24, 2003, the shareholders of BP voted at the AGM to adopt new Articles of Association to consolidate amendments which have been necessary to implement legislative changes since the previous Articles of Association were adopted in 1983.

At the AGM held on April 15, 2004, shareholders approved an amendment to the Articles of Association such that at each AGM held after December 31, 2004, all directors shall retire from office and may offer themselves for re-election. There have been no further amendments to the Articles of Association.

Objects and Purposes

BP is incorporated under the name BP p.l.c. and is registered in England and Wales with registered number 102498. Clause 4 of BP s Memorandum of Association provides that its objects include the acquisition of petroleum bearing lands; the carrying on of refining and dealing businesses in the petroleum, manufacturing, metallurgical or chemicals businesses; the purchase and operation of ships and all other vehicles and other conveyances; and the carrying on of any other businesses calculated to benefit BP. The memorandum grants BP a range of corporate capabilities to effect these objects.

Directors

The business and affairs of BP shall be managed by the directors.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which he has a material interest other than by virtue of his interest in shares in the Company. However, in the absence of some other material interest not indicated below, a director is entitled to vote and to be counted in a quorum for the purpose of any vote relating to a resolution concerning the following matters:

- the giving of security or indemnity with respect to any money lent or obligation taken by the director at the request or benefit of the Company;
- any proposal in which he is interested concerning the underwriting of Company securities or debentures;
- any proposal concerning any other company in which he is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that he and persons connected with him are not the holder or holders of 1% or more of the voting interest in the shares of such company;
- proposals concerning the modification of certain retirement benefits schemes under which he may benefit and which has been approved by either the UK Board of Inland Revenue or by the shareholders; and
- any proposal concerning the purchase or maintenance of any insurance policy under which he may benefit.

The UK Companies Act requires a director of a company who is in any way interested in a contract or proposed contract with the company to declare the nature of his interest at a meeting of the directors of the company. The definition of interest now includes the interests of spouses, children, companies and Trusts. The directors may exercise all the powers of the company to borrow money, except that the amount remaining undischarged of all moneys borrowed by the company shall not, without approval of the shareholders, exceed the amount paid up on the share capital plus the aggregate of the amount of the capital and revenue reserves of the company. Variation of the borrowing power of the board may only be effected by amending the Articles of Association.

Remuneration of non-executive directors shall be determined in the aggregate by resolution of the shareholders. Remuneration of executive directors is determined by the remuneration committee. This committee is made up of non-executive directors only. Any director attaining the age of 70 shall retire at the next AGM. There is no requirement of share ownership for a director s qualification.

Dividend Rights; Other Rights to Share in Company Profits; Capital Calls

If recommended by the directors of BP, BP shareholders may, by resolution, declare dividends but no such dividend may be declared in excess of the amount recommended by the directors. The directors may also pay interim dividends without obtaining shareholder approval. No dividend may be paid other than out of profits available for distribution, as determined under IFRS and the UK Companies Act. Dividends on ordinary shares are payable only after payment of dividends on BP preference shares. Any dividend unclaimed after a period of twelve years from the date of declaration of such dividend shall be forfeited and reverts to BP.

The directors have the power to declare and pay dividends in any currency provided that a sterling equivalent is announced. It is not the Company s intention to change its current policy of paying dividends in US dollars.

Apart from shareholders rights to share in BP s profits by dividend (if any is declared), the Articles of Association provide that the directors may set aside:

- a special reserve fund out of the balance of profits each year to make up any deficit of cumulative dividend on the BP preference shares; and

- a general reserve out of the balance of profits each year, which shall be applicable for any purpose to which the profits of the Company may properly be applied. This may include capitalization of such sum, pursuant to an ordinary shareholders resolution, and distribution to shareholders as if it were distributed by way of a dividend on the ordinary shares or in paying up in full unissued ordinary shares for allotment and distribution as bonus shares.

Any such sums so deposited may be distributed in accordance with the manner of distribution of dividends as described above.

Holders of shares are not subject to calls on capital by the Company, provided that the amounts required to be paid on issue have been paid off. All shares are fully paid.

Voting Rights

The Articles of Association of BP provide that voting on resolutions at a shareholders meeting will be decided on a poll other than resolutions of a procedural nature, which may be decided on a show of hands. If voting is on a poll, every shareholder who is present in person or by proxy has one vote for every ordinary share held and two votes for every £5 in nominal amount of BP preference shares held. If voting is on a show of hands, each shareholder who is present at the meeting in person or whose duly appointed proxy is present in person will have one vote, regardless of the number of shares held, unless a poll is requested. Shareholders do not have cumulative voting rights.

Holders of record of ordinary shares may appoint a proxy, including a beneficial owner of those shares, to attend, speak and vote on their behalf at any shareholders meeting.

Record holders of BP ADSs also are entitled to attend, speak and vote at any shareholders meeting of BP by the appointment by the approved depositary, JPMorgan Chase Bank, of them as proxies in

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respect of the ordinary shares represented by their ADSs. Each such proxy may also appoint a proxy. Alternatively, holders of ADSs are entitled to vote by supplying their voting instructions to the depositary, who will vote the ordinary shares represented by their ADSs in accordance with their instructions.

Proxies may be delivered electronically.

Matters are transacted at shareholders meetings by the proposing and passing of resolutions, of which there are three types: ordinary, special or extraordinary.

An ordinary resolution requires the affirmative vote of a majority of the votes of those persons voting at a meeting at which there is a quorum. Special and extraordinary resolutions require the affirmative vote of not less than three-fourths of the persons voting at a meeting at which there is a quorum. Any AGM at which it is proposed to put a special or ordinary resolution requires 21 days notice. An extraordinary resolution put to the AGM requires no notice period. Any extraordinary general meeting at which it is proposed to put a special resolution requires 21 days notice; otherwise, the notice period for an extraordinary general meeting is 14 days.

Liquidation Rights; Redemption Provisions

In the event of a liquidation of BP, after payment of all liabilities and applicable deductions under UK laws and subject to the payment of secured creditors, the holders of BP preference shares would be entitled to the sum of (i) the capital paid up on such shares plus, (ii) accrued and unpaid dividends and (iii) a premium equal to the higher of (a) 10% of the capital paid up on the BP preference shares and (b) the excess of the average market price over par value of such shares on the London Stock Exchange during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, BP may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolutions, by determination of the directors), and may issue shares which are to be or may be redeemed.

Variation of Rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or upon the adoption of an extraordinary resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the Articles of Association relating to proceedings at a general meeting apply, except that the quorum with respect to a meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one third or more of the shares of that class.

Shareholders Meetings and Notices

Shareholders must provide BP with a postal or electronic address in the UK in order to be entitled to receive notice of shareholders meetings. In certain circumstances, BP may give notices to shareholders by advertisement in UK newspapers. Holders of BP ADSs are entitled to receive notices under the terms of the deposit agreement relating to BP ADSs. The substance and timing of notices is described above under the heading Voting Rights.

Under the Articles of Association, the AGM of shareholders will be held within 15 months after the preceding AGM. All other general meetings of shareholders shall be called Extraordinary General Meetings and all general meetings shall be held at a time and place determined by the directors within the United Kingdom. If any shareholders meeting is adjourned for lack of quorum, notice of the time and place of the meeting may be given in any lawful manner, including electronically. Powers exist for action to be taken either before or at the meeting by authorized officers to ensure its orderly conduct and safety of those attending.

Limitations on Voting and Shareholding

There are no limitations imposed by English law or BP s Memorandum or Articles of Association on the right of non-residents or foreign persons to hold or vote the Company s ordinary shares or ADSs, other than limitations that would generally apply to all of the shareholders.

Disclosure of Interests in Shares

The UK Companies Act permits a public company, on written notice, to require any person whom the company believes to be or, at any time during the previous three years prior to the issue of the notice, to have been interested in its voting shares, to disclose certain information with respect to those interests. Failure to supply the information required may lead to disenfranchisement of the relevant shares and a prohibition on their transfer and receipt of dividends and other payments in respect of those shares. In this context the term interest is widely defined and will generally include an interest of any kind whatsoever in voting shares, including any interest of a holder of BP ADSs.

MATERIAL CONTRACTS

None.

EXCHANGE CONTROLS AND OTHER LIMITATIONS AFFECTING SECURITY HOLDERS

There are currently no UK foreign exchange controls or restrictions on remittances of dividends on the ordinary shares or on the conduct of the Company s operations.

There are no limitations, either under the laws of the UK or under the Articles of Association of BP p.l.c., restricting the right of non-resident or foreign owners to hold or vote BP ordinary or preference shares in the Company.

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TAXATION

This section describes the material United States federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder that holds the ordinary shares or ADSs as capital assets for tax purposes. It does not apply, however, to members of special classes of holders subject to special rules and holders that, directly or indirectly, hold 10% or more of the Company s voting stock.

A US holder is any beneficial owner of ordinary shares or ADSs that is for United States federal income tax purposes (i) a citizen or resident of the United States, (ii) a United States domestic corporation, (iii) an estate whose income is subject to United States federal income taxation regardless of its source, or (iv) a trust if a United States court can exercise primary supervision over the trust s administration and one or more United States persons are authorized to control all substantial decisions of the trust.

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations thereunder, published rulings and court decisions, and the taxation laws of the United Kingdom, all as currently in effect, as well as the income tax convention between the United States and the United Kingdom that entered into force on March 31, 2003 (the Treaty). These laws are subject to change, possibly on a retroactive basis.

For purposes of the Treaty and the estate and gift tax Convention (the Estate Tax Convention), and for United States federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the Company s ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs, and ADRs for ordinary shares, generally will not be subject to United States federal income tax or to UK taxation, other than stamp duty or stamp duty reserve tax, as described below.

This section is further based in part upon the representations of the Depositary and assumes that each obligation in the Deposit Agreement and any related agreement will be performed in accordance with its terms.

Investors should consult their own tax advisor regarding the United States federal, state and local, the UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Treaty.

Taxation of Dividends

United Kingdom Taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the Company, including dividends paid to US holders. A shareholder that is a company resident for tax purposes in the United Kingdom generally will not be taxable on a dividend it receives from the Company. A shareholder who is an individual resident for tax purposes in the United Kingdom is entitled to a tax credit on cash dividends paid on ordinary shares or ADSs of the Company equal to one-ninth of the cash dividend.

United States Federal Income Taxation

A US holder is subject to United States federal income taxation on the gross amount of any dividend paid by the Company out of its current or accumulated earnings and profits (as determined for United States federal income tax purposes). Dividends paid to a non-corporate US holder in taxable years beginning before January 1, 2011, that constitute qualified dividend income will be taxable to the holder at a maximum tax rate of 15%, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the Company with respect to the shares or ADSs will generally be qualified dividend income.

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As noted above in this Item United Kingdom Taxation, a US holder will not be subject to UK withholding tax. A US holder will include in gross income for United States federal income tax purposes the amount of the dividend actually received from the Company, and the receipt of a dividend will not entitle the US holder to a foreign tax credit.

For United States federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depositary, in the case of ADSs, actually or constructively receives the dividend, and will not be eligible for the dividends-received deduction generally allowed to United States corporations in respect of dividends received from other United States corporations. Dividends will be income from sources outside the United States, and generally will be passive income or, in the case of certain US holders, financial services income (or, for tax years beginning after December 31, 2006, general category income), which is treated separately from other types of income for purposes of computing the allowable foreign tax credit.

The amount of the dividend distribution on the ordinary shares or ADSs that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/ US dollar rate on the date the dividend distribution is includible in income, regardless of whether the payment is in fact converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is includible in income to the date the payment is converted into US dollars will be treated as ordinary income or loss. The gain or loss generally will be income or loss from sources within the United States for foreign tax credit limitation purposes.

Distributions in excess of the Company s earnings and profits, as determined for United States federal income tax purposes, will be treated as a return of capital to the extent of the US holder s basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described in this Item Taxation of Capital Gains United States Federal Income Taxation.

Taxation of Capital Gains

United Kingdom Taxation

A US holder may be liable for both United Kingdom and United States tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (i) a citizen of the United States resident or ordinarily resident in the United Kingdom, (ii) a United States domestic corporation resident in the United Kingdom by reason of its business being managed or controlled in the United Kingdom or (iii) a citizen of the United States or a corporation that carries on a trade or profession or vocation in the United Kingdom through a branch or agency or, in respect of corporations for accounting periods beginning on or after January 1, 2003, through a permanent establishment, and that have used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment. However, such persons may be entitled to a tax credit against their United States federal income tax liability for the amount of United Kingdom capital gains tax or UK corporation tax on chargeable gains (as the case may be) which is paid in respect of such gain.

Under the Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence of the relevant holder as determined under both the laws of the United Kingdom and the United States and as required by the terms of the Treaty.

Under the Treaty, individuals who are residents of either the United Kingdom or the United States and who have been residents of the other jurisdiction (the United States or the United Kingdom, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the Company not only in the jurisdiction of which the holder is resident at the time of the disposition but also in the other jurisdiction.

United States Federal Income Taxation

A US holder that sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for United States federal income tax purposes equal to the difference between the US dollar value of the amount realized and the holder s tax basis, determined in US dollars, in the ordinary shares or ADSs. Capital gain of a non-corporate US holder that is recognized in taxable years beginning before January 1, 2011, is generally taxed at a maximum rate of 15% if the holder s holding period for such ordinary shares or ADSs exceeds one year. The gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

Additional Tax Considerations

UK Inheritance Tax

The Estate Tax Convention applies to inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to UK inheritance tax on the individual s death or on transfer during the individual s lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK used for the performance of independent personal services. In the exceptional case where ADSs are subject both to inheritance tax and to US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

UK Stamp Duty and Stamp Duty Reserve Tax

The statements below relate to what is understood to be the current practice of the UK Inland Revenue under existing law.

Provided that the instrument of transfer is not executed in the UK and remains at all times outside the UK, and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of 50 pence per £100 (or part), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser. A subsequent transfer of ordinary shares to the Depositary s nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer.

A transfer of the underlying ordinary shares to an ADR holder upon cancellation of the ADSs without transfer of beneficial ownership will give rise to UK stamp duty at the rate of £5 per transfer.

An ADR holder electing to receive ADSs instead of a cash dividend will be responsible for the stamp duty reserve tax due on issue of shares to the Depositary s nominee and calculated at the rate of 1.5% on the issue price of the shares. Current UK Inland Revenue practice is to calculate the issue price by reference to the total cash receipt (i.e, cash dividend plus the Refund if any) to which a US Holder would have been entitled had the election to receive ADSs instead of a cash dividend not been made. ADR holders electing to receive ADSs instead of the cash dividend authorize the Depositary to sell sufficient shares to cover this liability.

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DOCUMENTS ON DISPLAY

It is possible to read and copy documents referred to in this annual report on Form 20-F that have been filed with the SEC at the SEC s public reference room located at 100 F Street NE, Washington, DC 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference rooms and their copy charges. The SEC filings are also available to the public from commercial document retrieval services and, for most recent BP periodic filings only, at the Internet world wide web site maintained by the SEC at www.sec.gov.

ITEM 11 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Group is exposed to a number of different market risks arising from its normal business activities. Market risk is the possibility that changes in foreign currency exchange rates, interest rates, or oil and natural gas or power prices, will affect adversely affect the value of the Group s financial assets, liabilities or expected future cash flows. The Group has developed policies aimed at managing the volatility inherent in certain of these natural business exposures and in accordance with these policies the Group enters into various transactions using derivative financial and commodity instruments (derivatives). Derivatives are contracts whose value is derived from one or more underlying financial or commodity instruments, indices or prices which are defined in the contract. The Group also trades derivatives in conjunction with its risk management activities.

All derivative activity, whether for risk management or trading, is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control, meeting generally accepted industry practice and reflecting the principles of the Group of Thirty Global Derivatives Study recommendations. Independent control functions monitor compliance with the Group s policies. A Trading Risk Management Committee has oversight of the quality of internal control in the Group s trading function. The control framework includes prescribed trading limits that are reviewed regularly by senior management, daily monitoring of risk exposure using value-at-risk principles, marking trading exposures to market and stress testing to assess the exposure to potentially extreme market situations. The Group s operational, risk management and trading activities in oil, natural gas, power and financial markets are managed within a single integrated function that has the responsibility for ensuring high and consistent standards of control, making investments in the necessary systems and supporting infrastructure and providing professional management oversight.

In market risk management and trading, conventional exchange-traded derivatives such as futures and options are used, as well as non-exchange-traded instruments such as over-the-counter swaps, options and forward contracts.

IAS 39 Financial Instruments: Recognition and Measurement (IAS 39) prescribes strict criteria for hedge accounting, whether as a cash flow or fair value hedge, and requires that any derivative that does not meet these criteria should be classified as held for trading purposes and marked-to-market. BP adopted IAS 32 and IAS 39 with effect from January 1, 2005 without restating prior periods. Consequently, the Group s accounting policy under UK GAAP has been used for 2004 and 2003. The policy under UK GAAP and the disclosures required by UK GAAP for derivative financial instruments are shown in Item 18 Financial Statements Note 38 on page F-97.

Where derivatives constitute a fair value hedge, the Group s exposure to market risk created by the derivative is offset by the opposite exposure arising from the asset, liability or transaction being hedged. Gains and losses relating to derivatives designated as part of a cash flow hedge are taken to reserves and recycled through income as the hedged item is recognized. By contrast, where derivatives are held for trading purposes, realized and unrealized gains and losses are recognized in the period in which they occur.

The Group also has embedded derivatives held for trading. Prior to the development of an active gas trading market, UK gas contracts were priced using a basket of available price indices, primarily relating to oil products. Post the development of an active UK gas market, certain contracts were entered into or renegotiated using pricing formulae not related directly to gas prices, for example, oil product and power prices. In these circumstances, pricing formulae have been determined to be derivatives, embedded within the overall contractual arrangements that are not clearly and closely related to the underlying commodity. The resulting fair value relating to these contracts is recognized on the balance sheet with gains or losses recognized in the income statement.

Further information about BP s use of derivatives, their characteristics and the IFRS accounting treatment thereof is given in Item 18 Financial Statements Note 1 and Note 37 on pages F-12 and F-83.

There are minor differences in the criteria for hedge accounting under IFRS and SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities . Prior to January 1, 2005, the Group did not designate any of its derivative financial instruments as part of hedged transactions under SFAS 133. As a result, all changes in fair value were recognized through earnings. See Item 18 Financial Statements Note 55 on page F-191 for further information.

Foreign Currency Exchange Rate Risk

Fluctuations in exchange rates can have significant effects on the Group s reported results. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates, and conversion differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the Group s reported results.

The main underlying economic currency of the Group s cash flows is the US dollar. This is because BP s major product, oil, is priced internationally in US dollars. BP s foreign exchange management policy is to minimize economic and material transactional exposures arising from currency movements against the US dollar. The Group co-ordinates the handling of foreign exchange risks centrally, by netting off naturally occurring opposite exposures wherever possible, to reduce the risks, and then dealing with any material residual foreign exchange risks. The most significant residual exposures are capital expenditure and UK and European operational requirements. In addition, most of the Group s borrowings are in US dollars or are hedged with respect to the US dollar. At December 31, 2005, the total of foreign currency borrowings not swapped into US dollars amounted to $424 million. The principal elements of this are $150 million of borrowings in euros, $76 million in sterling, $81 million in Canadian dollars and $83 million in Trinidad and Tobago dollars.

The following table provides information about the Group s foreign currency derivative financial instruments. These include foreign currency forward exchange agreements (forwards), cylinder option contracts (cylinders), and purchased call options that are sensitive to changes in the sterling/ US dollar and euro/ US dollar exchange rates. Where foreign currency denominated borrowings are swapped into US dollars using forwards or cross currency swaps such that currency risk is completely eliminated, neither the borrowing nor the derivative are included in the table.

For forwards, the tables present the notional amounts and weighted average contractual exchange rates by contractual maturity dates and exclude forwards that have offsetting positions. Only significant forward positions are included in the tables. The notional amounts of forwards are translated into US dollars at the exchange rate included in the contract at inception. The fair value represents an estimate of the gain or loss which would be realized if the contracts were settled at the balance sheet date.

Cylinders consist of purchased call option and written put option contracts. For cylinders and purchased call options, the tables present the notional amounts of the option contracts at December 31, 2005 and the weighted average strike rates.

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The fair values for the foreign exchange contracts in the table below are based on market prices of comparable instruments (forwards) and pricing models which take into account relevant market data (options). These derivative contracts constitute a hedge; any change in the fair value or expected cash flows is offset by an opposite change in the market value or expected cash flows of the asset, liability or transaction being hedged.

Notional amount by expected maturity date

	2006	2007	2008	2009	2010	Beyond 2010	Total	Fair value asset/ (liability)
					($ million)			
At December 31, 2005								
Forwards								
Receive sterling/pay US dollars								
Contract amount	1,749	128	25	6	5	22	1,935	(66)
Weighted average contractual exchange rate	1.78							
Receive sterling/pay euro								
Contract amount	67	1					68	1
Weighted average contractual exchange rate	£0.70							
Receive euro/pay US dollars								
Contract amount	1,253	102	26	11	8	30	1,430	(13)
Weighted average contractual exchange rate	1.22							
Cylinders								
Receive sterling/pay US dollars								
Purchased call								
Contract amount	717						717	3
Weighted average strike price	1.84							
Sold put								
Contract amount	717						717	(27)
Weighted average strike price	1.77							
Receive Euro/pay US dollars								
Purchased call								
Contract amount	706						706	3
Weighted average strike price	1.29							
Sold put								
Contract amount	706						706	(23)
Weighted average strike price	1.21							
Purchased call options								
Receive sterling/pay US dollars								
Purchased call								
Contract Amount	533						533	0
Weighted average strike price	1.97							
Receive euro/pay US dollars								
Purchased call								

Contract Amount	207	207	0
Weighted average strike price	1.42		

(a) Weighted average contractual exchange rates are expressed as US dollars per non-US dollar currency unit.

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Notional amount by expected maturity date

	2005	2006	2007	2008	2009	Beyond 2009	Total	Fair value asset/ (liability)
				($ million)				
At December 31, 2004								
Forwards								
Receive sterling/pay US dollars								
Contract amount	2,559	136	61	21	9	35	2,821	253
Weighted average contractual exchange rate	1.75							
Receive sterling/pay euro								
Contract amount	24	29	15				68	(2)
Weighted average contractual exchange rate	£0.72							
Receive euro/pay US dollars								
Contract amount	237	78	28	11	10	36	400	69
Weighted average contractual exchange rate	1.18							
Pay euro/receive US dollars								
Contract amount	1,829	5					1,834	(5)
Weighted average contractual exchange rate	1.35							
Receive Norwegian krone/pay US dollars								
Contract amount	232	4					236	22
Weighted average contractual exchange rate (a)	6.66							
Cylinders								
Receive sterling/pay US dollars								
Purchased call								
Contract amount	904						904	32
Weighted average strike price	1.87							
Sold put								
Contract amount	904						904	(3)
Weighted average strike price	1.75							
Purchased call options								
Receive sterling/pay US dollars								
Purchased call								
Contract amount	1,467						1,467	18
Weighted average strike price	1.97							
Receive euro/pay US dollars								
Purchased call								
Contract Amount	1,182						1,182	9
Weighted average strike price	1.44							

(a) Weighted average contractual exchange rates are expressed as US dollars per non-US dollar currency unit except Norwegian krone which are expressed as krone per US dollar.

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Interest Rate Risk

BP is exposed to interest rate risk on short- and long-term floating rate instruments and as a result of the refinancing of fixed rate finance debt. The Group is exposed predominantly to US dollar LIBOR (London Inter-Bank Offer Rate) interest rates as borrowings are mainly denominated in, or are swapped into, US dollars. To manage the balance between fixed and floating rate debt, the Group enters into interest rate and cross-currency swaps in which the Group agrees to exchange, at specified intervals, the difference between fixed and variable rate interest amounts calculated by reference to an agreed notional principal amount. The proportion of floating rate debt at December 31, 2005 was 96% of total finance debt outstanding.

The following table shows, by major currency, the Group s finance debt at December 31, 2005 and 2004 and the weighted average interest rates achieved at those dates through a combination of borrowings and other interest rate sensitive instruments entered into to manage interest rate exposure.

	Fixed rate debt			Floating rate debt		
	Weighted average interest rate	Weighted average time for which rate is fixed	Amount	Weighted average interest rate	Amount	Total
	(%)	(years)	($ million)	(%)	($ million)	($ million)
At December 31, 2005						
US dollar	7	11	665	5	18,073	18,738
Sterling				6	76	76
Euro				3	150	150
Other currencies	9	14	157	12	41	198
Total loans			822		18,340	19,162
At December 31, 2004						
US dollar	7	11	707	3	21,789	22,496
Sterling				5	96	96
Euro				3	297	297
Other currencies	9	15	167	8	35	202
Total loans			874		22,217	23,091

The Group s earnings are sensitive to changes in interest rates over the forthcoming year as a result of the floating rate instruments included in the Group s finance debt at December 31, 2005. These include the effect of interest rate and currency swaps and forwards utilized to manage interest rate risk. If the interest rates applicable to floating rate instruments were to have increased by 1% on January 1, 2006, the Group s 2006 earnings before taxes would decrease by approximately $180 million. This assumes that the amount and mix of fixed and floating rate debt, including finance leases, remains unchanged from that in place at December 31, 2005 and that the change in interest rates is effective from the beginning of the year. Where the interest rate applicable to an instrument is reset during a quarter it is assumed that this occurs at the beginning of the quarter and remains unchanged for the rest of the year. In reality, the fixed/floating rate mix will fluctuate over the year and interest rates will change continually. Furthermore the effect on earnings shown by this analysis does not consider the effect of an overall reduction in economic activity which could accompany such an increase in interest rates.

Derivatives Held For Trading

In conjunction with the risk management activities discussed above the Group also trades interest rate and foreign exchange rate derivatives and, in addition, undertakes trading and risk management of certain specified commodities. In order to disclose a complete picture of activities in relation to commodity derivatives, all activity (trading and risk management) is included in aggregate in the following tables.

The Group s operational, risk management and trading activities in oil, natural gas, power and financial markets are managed within a single integrated function. The Group s risk management policy requires the management of only certain short-term exposures in respect of its equity share of production and certain of its refinery and marketing activities. These risks are managed in combination with the Group s supply and trading activities.

To this end, the Group s supply and trading function uses the full range of conventional financial and commodity derivatives available in the related commodity markets. Natural gas swaps, options and futures are used to convert specific sale and purchase contracts from fixed prices to market prices. Swaps are also used to manage exposures to gas price differentials between locations. The Group s oil supply and trading activities undertake the full range of conventional derivative financial and commodity instruments and physical cargoes available in the commodity markets. Power trading is undertaken using a combination of over-the-counter forward contracts and other derivative contracts including options and futures. This activity is on both a standalone basis and in conjunction with gas derivatives in relation to gas generated power margin. In addition, NGL s are traded around certain US inventory locations using over-the-counter forward contracts in conjunction with over-the-counter swaps, options and physical inventories.

The Group measures its market risk exposure, i.e., potential gain or loss in fair value, on its trading activity using value-at-risk techniques. These techniques are based on a variance/ covariance model or a Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market values over a 24-hour period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures, and the history of one-day price movements, together with the correlation of these price movements. The Group calculates value-at-risk for the bulk of instruments and exposures in the held-for-trading category, other than the UK North Sea natural gas embedded derivatives, for which a sensitivity analysis is calculated.

The Group has calculated previously and published value-at-risk expressed to three standard deviations for the internal delegation of market risk limits and control purposes. This is equivalent to a 99.7% confidence interval or a probability of one day per year where the daily gain or loss will exceed the calculated value-at-risk if the portfolio was left unchanged. In order to improve the practical application of this tool, the Group has adopted a 95% confidence level, or calculation to 1.65 standard deviations. This has the effect of increasing the expected frequency of occasions when the daily gain or loss may exceed the calculated value-at-risk to one per month if the portfolio is left unchanged. This provides a better opportunity for verifying models and assumptions and improving accuracy of the value-at-risk calculation. For completeness, 2005 value-at-risk data has been disclosed using both the 99.7% and 95% confidence levels but in future only value-at-risk data on a 95% basis will be disclosed.

The value-at-risk model takes account of derivative financial instrument types such as interest rate forward and futures contracts, swap agreements, options and swaptions, foreign exchange forward and futures contracts, swap agreements and options, and oil, natural gas and power price futures, swap agreements and options. Financial assets and liabilities and physical crude oil and refined products that are treated as held for trading positions are also included in these calculations. The value-at-risk calculation for oil, natural gas, NGL and power price exposure also includes cash-settled commodity contracts such as forward contracts. For options, a linear approximation is included in the value-at-risk models.

The following table shows values-at-risk for held for trading activities described above.

	High	Low	Average	At December 31,
			($ million)	
Value at risk on three standard deviations:				
2005				
Interest rate trading	2			
Foreign exchange trading	9	2	4	2
Oil price trading	145	31	60	56
Natural gas and NGL price trading	71	9	26	30
Power price trading	30	4	14	16
2004				
Interest rate trading	1			
Foreign exchange trading	4	1	1	1
Oil price trading	55	18	29	45
Natural gas and NGL price trading	42	11	23	18
Power price trading	18	2	8	7
2003				
Interest rate trading	1			
Foreign exchange trading	4		2	1
Oil price trading	34	17	26	27
Natural gas and NGL price trading	29	4	16	18
Power price trading	13		4	6

	High	Low	Average	At December 31,
			($ million)	
Value at risk on 1.65 standard deviations:				
2005				
Interest rate trading	1			
Foreign exchange trading	5	1	2	1
Oil price trading	80	17	33	31
Natural gas and NGL price trading	39	6	15	17
Power price trading	16	2	7	9
2004				
Interest rate trading	1			
Foreign exchange trading	2	1	1	1
Oil price trading	30	10	16	25
Natural gas and NGL price trading	23	6	13	10
Power price trading	10	1	4	4
2003				
Interest rate trading	1			
Foreign exchange trading	2		1	1
Oil price trading	19	9	14	15
Natural gas and NGL price trading	16	2	9	10

Power price trading	7	2	3

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Sensitivity Analysis of Embedded Derivatives

Detailed below for the embedded derivatives is a sensitivity of the fair value to immediate 10% favourable and adverse changes in the key assumptions.

	At December 31, 2005
Remaining contract terms	3 to 13 years
Contractual/notional amount	8,220 million therms
Discount rate nominal risk free	4.5%
Fair value liability	$2,590 million

	At December 31, 2005			
	Natural gas price	Gas oil and fuel oil price	Power price	Discount rate
	($ million)			
Favourable 10% change	408	30	(63)	34
Unfavourable 10% change	(427)	(45)	58	(34)

	At December 31, 2004
Remaining contract terms	4 to 14 years
Contractual/ notional amount	10,409 million therms
Discount rate nominal risk free	4.5%
Fair value liability	$817 million

	At December 31, 2004			
	Natural gas price	Gas oil and fuel oil price	Power price	Discount rate
	($ million)			
Favourable 10% change	129	9	(20)	11
Unfavourable 10% change	(135)	(14)	18	(11)

These sensitivities are hypothetical and should not be considered to be predictive of future performance. Changes in fair value generally cannot be extrapolated because the relationship of change in assumption to change in fair value may not be linear. Also, in this table, the effect of a variation in a particular assumption on the fair value of the embedded derivatives is calculated independently of any change in another assumption. In reality, changes in one factor may contribute to changes in another, which may magnify or counteract the sensitivities. Furthermore, the estimated fair values as disclosed should not be considered indicative of future earnings on these contracts.

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The following tables show the changes during the year in the net fair value of derivatives held for trading purposes for the years 2005 and 2004.

	Fair value interest rate contracts	Fair value exchange rate contracts	Fair value oil price contracts	Fair value natural gas and NGL price contracts	Fair value power price contracts
			($ million)		
Fair value of contracts at January 1, 2005		(54)	(171)	558	177
Contracts realized or settled in the year		23	175	(735)	76
Fair value of new contracts when entered into during the year				24	10
Fair value of over-the-counter options at inception			(73)	(65)	(9)
Change in fair value due to changes in valuation techniques or key assumptions					
Other changes in fair values		54	8	747	(71)
Fair value of contracts at December 31, 2005		23	(61)	529	183
Fair value of contracts at January 1, 2004		(24)	(169)	302	134
Contracts realized or settled in the year		9	173	230	54
Fair value of new contracts when entered into during the year				15	
Fair value of over-the-counter options at inception			(33)	58	(3)
Change in fair value due to changes in valuation techniques or key assumptions					
Other changes in fair values		(39)	(142)	(47)	(8)
Fair value of contracts at December 31, 2004		(54)	(171)	558	177

The following tables show the changes during the year in the net fair value of embedded derivatives held for trading purposes for the years 2005 and 2004.

	Fair value interest rate contracts	Fair value natural gas price contracts
	($ million)	
Fair value of contracts at January 1, 2005	(17)	(659)

Contracts realized or settled in the year		138
Fair value of new contracts when entered into during the year		
Change in fair value due to changes in valuation techniques or key assumptions		
Other changes in fair values	(13)	(1,990)
Fair value of contracts at December 31, 2005	(30)	(2,511)
Fair value of contracts at January 1, 2004	(12)	(301)
Contracts realized or settled in the year		
Fair value of new contracts when entered into during the year		
Change in fair value due to changes in valuation techniques or key assumptions		
Other changes in fair values	(5)	(358)
Fair value of contracts at December 31, 2004	(17)	(659)

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The following table shows the fair value of day one profit deferred on the balance sheet.

	Fair value natural gas and NGL price contracts	Fair value power price contracts
	($ million)	
Fair value of contracts not recognized through the income statement at January 1, 2005	(15)	
Fair value of new contracts at inception not recognized in the income statement	(14)	(10)
Fair value recycled from equity into the income statement		
Other changes in fair values		
Fair value of contracts not recognized through profit at December 31, 2005	(29)	(10)

	Fair value natural gas and NGL price contracts	Fair value power price contracts
	($ million)	
Fair value of contracts not recognized through the income statement at January 1, 2004		
Fair value of new contracts at inception not recognized in the income statement	(15)	
Fair value recycled from equity into the income statement		
Other changes in fair values		
Fair value of contracts not recognized through profit at December 31, 2004	(15)	

The following tables show the net fair value of derivatives held for trading at December 31, 2005 and 2004 analyzed by maturity period and by methodology of fair value estimation.

	Fair value of contracts at December 31, 2005						
	Maturity less than 1 year	Maturity 1-2 years	Maturity 2-3 years	Maturity 3-4 years	Maturity 4-5 years	Over 5 years	Total fair value
				($ million)			
Prices actively quoted	(100)	(86)	46	42	33	(8)	(73)
	660	(48)	(41)	60	(11)		620

Prices sourced from observable data or market corroboration							
Prices based on models and other valuation methods	3	(2)	3	75	2	46	127
	563	(136)	8	177	24	38	674

Fair value of contracts at December 31, 2004

	Maturity less than 1 year	Maturity 1-2 years	Maturity 2-3 years	Maturity 3-4 years	Maturity 4-5 years	Over 5 years	Total fair value
				($ million)			
Prices actively quoted	105	(90)	13	21	17	15	81
Prices sourced from observable data or market corroboration	128	130	39	28	34		359
Prices based on models and other valuation methods	4	2	1	2	(1)	62	70
	237	42	53	51	50	77	510

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Prices actively quoted refers to the fair value of contracts valued in whole using prices actively quoted, for example, exchange-traded and UK National Balancing Point (NBP) contracts. Prices provided by other external sources refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data or internal inputs, for example, swaps and physical forward contracts. Prices based on models and other valuation methods refers to the fair value of a contract valued in part using internal models due to the absence of quoted prices, including over-the-counter options. The net change in fair value of contracts based on models and other valuation methods during the year is a gain of $130 million.

The following tables show the net fair value of embedded derivatives held for trading at December 31, 2005 and 2004 analyzed by maturity period and by methodology of fair value estimation.

	Fair value of contracts at December 31, 2005						
	Maturity less than 1 year	Maturity 1-2 years	Maturity 2-3 years	Maturity 3-4 years	Maturity 4-5 years	Over 5 years	Total fair value
				($ million)			
Prices actively quoted							
Prices sourced from observable data or market corroboration	51	28					79
Prices based on models and other valuation methods	(674)	(542)	(426)	(231)	(182)	(565)	(2,620)
	(623)	(514)	(426)	(231)	(182)	(565)	(2,541)

	Fair value of contracts at December 31, 2004						
	Maturity less than 1 year	Maturity 1-2 years	Maturity 2-3 years	Maturity 3-4 years	Maturity 4-5 years	Over 5 years	Total fair value
				($ million)			
Prices actively quoted							
Prices sourced from observable data or market corroboration	150	9					159
Prices based on models and other valuation methods	(247)	(206)	(141)	(102)	(57)	(82)	(835)
	(97)	(197)	(141)	(102)	(57)	(82)	(676)

ITEM 12 DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

Not applicable

PART II

ITEM 13 DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

None.

ITEM 14 MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

None.

ITEM 15 CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures as such term is defined in Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed in reports the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including the Company s group chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, our management, including the group chief executive and chief financial officer, recognize that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. Further, in the design and evaluation of our disclosure controls and procedures our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures. Also, we have investments in certain unconsolidated entities. As we do not control these entities, our disclosure controls and procedures with respect to such entities are necessarily substantially more limited than those we maintain with respect to our consolidated subsidiaries. Because of the inherent limitations in a cost-effective control system, mis-statements due to error or fraud may occur and not be detected. The Company s disclosure controls and procedures have been designed to meet, and management believe that they meet, reasonable assurance standards.

During 2005, a review was undertaken into the accounting treatment under US GAAP for over-the-counter forward contracts in oil, gas, NGLs and power in the context of the review undertaken for final transition to IFRS. As a result of this review the Group reassessed its recognition of revenues associated with these contracts under US GAAP and determined that these contracts should be reported net. Under the provisions of APB 20 the Company s management concluded that the change represented the correction of an accounting error. In addition, in connection with the preparation of the Form 20-F for the year ended December 31, 2005, the Company identified additional transactions which should also have been presented net under US GAAP. As a result of these matters, revenues and cost of sales for US GAAP were restated, and the Company s Annual Report on Form 20-F for the year ended December 31, 2004 was amended. The restatement for US GAAP purposes did not impact the Group s profit for the year as adjusted to accord with US GAAP, profit per ordinary share, cash flow or financial position.

Following the review of the accounting treatment for over-the counter forward contracts under US GAAP, the Group improved its disclosure controls and procedures by changing its US GAAP accounting policy for OTC forward contracts to conform to US GAAP, training the accounting staff regarding the policy change, implementing changes in its internal reporting systems to process and report sale and purchase contracts, in accordance with Group US GAAP accounting policy for such transactions and increasing management oversight of compliance therewith.

The Company s management, with the participation of the Company s group chief executive and the chief financial officer, has evaluated the effectiveness of the Company s disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this annual report. While the improvements in the Company s disclosure controls and procedures described in the preceding paragraph had largely been implemented by the end of 2005, the Group subsequently identified additional transactions which should also have been presented net under US GAAP. As a result of the identification of these additional transactions which should have been presented net under US GAAP, the group chief executive and the chief financial officer have determined that the Company s disclosure controls and procedures as of December 31, 2005 were not effective to provide reasonable assurance that information required to be disclosed in the Company s reports filed or submitted under the Exchange Act was recorded, processed, summarized and reported within the time period specified in the rules and forms of the SEC.

Apart from the failure to account for certain OTC forward contracts on a net basis under US GAAP, the Company s management has not identified any other deficiencies that would have led the Company s management to conclude that the Group s disclosure controls and procedures were ineffective for the period covered by this annual report. As the Company is not currently required to report on management s assessment of the effectiveness of the Group s internal controls over financial reporting the Company has not undertaken the kind of review of such controls that would be required in order to make such a report.

Changes in Internal Controls

The improvements in disclosure controls and procedures relating to the accounting treatment for OTC forward contracts under US GAAP implemented during 2005, as described above, also constituted changes in the Group s internal controls over financial reporting.

Aside from these improvements, there were no changes in the Group s internal controls over financial reporting that occurred during the period covered by this Form 20-F that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

ITEM 16A AUDIT COMMITTEE FINANCIAL EXPERT

Douglas Flint joined the board as a non-executive director on January 1, 2005 and joined the audit committee on March 16, 2005. He is group finance director of HSBC Holdings plc, and a former member of the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board. The Board determined that Mr Flint met the independence criteria provisions of Rule 10A-3 of the US Securities Exchange Act of 1934 and that Mr Flint may be regarded as an audit committee financial expert as defined for purposes of disclosure in Item 16A of Form 20-F.

ITEM 16B CODE OF ETHICS

The Company has adopted a Code of Ethics for its group chief executive, deputy group chief executive, chief financial officer, the general auditor, group chief accounting officer and group controller as required by the provisions of Section 406 of the Sarbanes-Oxley Act of 2002 and the rules issued by the SEC. There have been no amendments to, or waivers from, the Code of Ethics relating to any of those officers. The Code of Ethics has been filed as an exhibit to this report.

In June 2005, BP published a Code of Conduct which is applicable to all employees.

ITEM 16C PRINCIPAL ACCOUNTANT FEES AND SERVICES

The Audit Committee has established policies and procedures for the engagement of the independent registered public accounting firm, Ernst & Young LLP, to render audit and certain

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assurance and tax services. The policies provide for pre-approval by the audit committee of specifically defined audit, audit-related, tax and other services that are not prohibited by regulatory or other professional requirements. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young relative to that of other potential service providers. These services are for a fixed term.

Under the policy, pre-approval is given for specific services within the following categories: advice on accounting, auditing and financial reporting matters; internal accounting and risk management control reviews (excluding any services relating to information systems design and implementation); non-statutory audit; project assurance and advice on business and accounting process improvement (excluding any services relating to information systems design and implementation relating to BP s financial statements or accounting records); due diligence in connection with acquisitions, disposals and joint ventures; income tax and indirect tax compliance and advisory services; and employee tax services (excluding tax services that could impair independence); and provision of Ernst & Young publications. Additionally, any proposed service not included in the pre-approved services, must be approved in advance prior to commencement of the engagement. The Audit Committee has delegated to the Chair of the Audit Committee authority to approve permitted services provided that the Chair reports any decisions to the committee at its next scheduled meeting.

	Year ended December 31,		
	2005	**2004**	**2003**
		($ million)	
Audit fees Ernst & Young			
Group audit	47	27	18
Audit-related regulatory reporting	6	7	5
Statutory audit of subsidiaries	23	16	13
	76	50	36
Innovene operations	(8)	(2)	(2)
Continuing operations	68	48	34
Fees for other services Ernst & Young			
Further assurance services			
Acquisition and disposal due diligence	2	7	9
Pension scheme audits	1	1	1
Other further assurance services	7	9	9
	10	17	19
Tax services			
Compliance services	10	13	17
Advisory services		1	2
	10	14	19
Innovene operations	(1)	(1)	
Continuing operations	19	30	38

The audit fees payable to Ernst & Young are reviewed by the Audit Committee in the context of other global companies for cost effectiveness. The committee keeps under review the scope and results of audit work, its cost-effectiveness and the independence and objectivity of the auditors. It requires the auditors to rotate their lead audit partner every five years.

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Other further assurance services within Further assurance services include $4 million (2004 $3 million and 2003 $2 million) in respect of advice on accounting, auditing and financial reporting matters; $nil (2004 $1 million and 2003 $1 million) in respect of internal accounting and risk management control reviews; $3 million (2004 $3 million and 2003 $2 million) in respect of non-statutory audits and $nil (2004 $2 million and 2003 $3 million) in respect of project assurance and advice on business and accounting process improvement.

The tax compliance services relate to income tax and indirect tax compliance and employee tax services.

Fees paid to major firms of accountants other than Ernst & Young for other services amount to $151 million (2004 $82 million and 2003 $44 million).

ITEM 16D EXEMPTIONS FROM THE LISTING STANDARDS FOR AUDIT COMMITTEES

Not applicable.

ITEM 16E PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PURCHASERS

The following table provides details of ordinary shares repurchased.

	Total number of shares purchased (a)	Average price paid per share ($)	Total number of shares purchased as part of publicly announced programmes	Maximum number of shares that may yet be purchased under the programme (b)
2005				
January (c)	57,900,000	9.71	57,900,000	
February (d)	69,500,000	10.41	69,500,000	
March	65,725,000	10.86	65,725,000	
April	62,656,000	10.38	62,656,000	
May	63,627,000	10.13	63,627,000	
June	76,385,000	10.53	76,385,000	
July	161,074,724	11.02	161,074,724	
August	108,525,357	11.56	108,525,357	
September	62,517,400	11.99	62,517,400	
October	133,833,000	11.12	133,833,000	
November	121,578,400	11.23	121,578,400	
December	76,384,600	11.32	76,384,600	
2006				
January	70,000,000	11.67	70,000,000	
February	139,785,200	11.41	139,785,200	
March	139,294,200	11.41	139,294,200	
April	107,608,638	12.22	107,608,638	
May	149,312,153	12.33	149,312,153	
June (through June 28)	118,823,000	11.31	118,823,000	

(a) All share purchases were open market transactions.
(b) At the AGM on April 20, 2006, authorization was given to repurchase up to 2 billion ordinary shares in the period to the next AGM or July 19, 2007, the latest date by which an AGM must be held. This authorization is renewed annually at the AGM.
(c) Shares repurchased for cancellation.
(d) Includes 18,900,000 shares repurchased for cancellation and 50,600,000 shares held in treasury.

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The following table provides details of share purchases made by ESOP Trusts.

	Total number of shares purchased	Average price paid per share ($)	Total number of shares purchased as part of publicly announced programmes (a)	Maximum number of shares that may yet be purchased under the programme (a)
2005				
January	143,789	9.79		
February	7,128,864	10.47		
March	6,271,709	10.39		
April	239	9.53		
May				
June	3,690	10.82		
July	10,000,000	11.69		
August				
September	2,030	10.33		
October				
November				
December	3,028	9.35		
2006				
January	41,068	11.24		
February	1,638,669	11.33		
March	6,198,758	11.47		
April				
May	13,829	12.37		
June (through June 28)	10,001,371	10.93		

(a) No shares were repurchased pursuant to a publicly announced plan. Transactions represent the purchase of ordinary shares by ESOP Trusts to satisfy future requirements of employee share schemes.

PART III

ITEM 17 FINANCIAL STATEMENTS

Not applicable.

ITEM 18 FINANCIAL STATEMENTS

The following financial statements, together with the reports of the Independent Registered Public Accounting Firm thereon, are filed as part of this annual report:

The following supplementary information is filed as part of this annual report:

ITEM 19 EXHIBITS

The following documents are filed as part of this annual report:

Exhibit 1.	Memorandum and Articles of Association of BP p.l.c.*
Exhibit 4.1	The BP Executive Directors Incentive Plan**
Exhibit 4.2	Directors Service Contracts**
Exhibit 4.3	Medium Term Performance Plan
Exhibit 4.4	Deferred Annual Bonus Plan
Exhibit 7.	Computation of Ratio of Earnings to Fixed Charges (Unaudited)
Exhibit 8.	Subsidiaries
Exhibit 11.	Code of Ethics*
Exhibit 12.	Rule 13a 14(a) Certifications
Exhibit 13.	Rule 13a 14(b) Certifications#

* Incorporated by reference to the Company s Annual Report on Form 20-F for the year ended December 31, 2003.

** Incorporated by reference to the Company s Annual Report on Form 20-F for the year ended December 31, 2004.

Furnished only.

The total amount of long-term debt securities of the Registrant and its subsidiaries authorized under any one instrument does not exceed 10% of the total assets of BP p.l.c. and its subsidiaries on a consolidated basis. The Company agrees to furnish copies of any or all such instruments to the Securities and Exchange Commission upon request.

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BP p.l.c. AND SUBSIDIARIES
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To: The Board of Directors
BP p.l.c.

We have audited the accompanying consolidated balance sheets of BP p.l.c. as of December 31, 2005, 2004 and 2003, and the related consolidated statements of income, cash flows, recognized income and expense, and changes in BP shareholders equity for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule listed in the Index at Item 18. These financial statements and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of BP p.l.c. at December 31, 2005 and 2004, and the consolidated results of its operations and its consolidated cash flows for each of the three years in the period ended December 31, 2005, in accordance with International Financial Reporting Standards as adopted by the European Union which differ in certain respects from United States generally accepted accounting principles (see Note 55 of Notes to Financial Statements). Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 37 of Notes to Financial Statements, the Group changed its method of accounting for derivative financial instruments in 2005.

/s/ ERNST & YOUNG LLP

Ernst & Young LLP

London, England
June 30, 2006

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BP p.l.c. AND SUBSIDIARIES

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference of our report dated June 30, 2006, with respect to the consolidated financial statements and schedule of BP p.l.c. included in this Annual Report (Form 20-F) for the year ended December 31, 2005 in the following Registration Statements:

Registration Statements on Form F-3 (File Nos. 333-9790, 333-65996 and 333-110203) of BP p.l.c.;

Registration Statement on Form F-3 (File No. 333-83180) of BP Australia Capital Markets Limited, BP Canada Finance Company, BP Capital Markets p.l.c., BP Capital Markets America Inc. and BP p.l.c.; and

Registration Statements on Form S-8 (File Nos. 33-21868, 333-9020, 333-9798, 333-79399, 333-34968, 333-67206, 333-74414, 333-102583, 333-103923, 333-103924, 333-119934, 333-123482, 333-123483, 333-132619, 333-131584 and 333-131583) of BP p.l.c.

/s/ ERNST & YOUNG LLP

Ernst & Young LLP

London, England
June 30, 2006

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BP p.l.c. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF INCOME

		Years ended December 31,		
	Note	**2005**	**2004**	**2003**
		($ million, except per share amounts)		
Sales and other operating revenues	7	239,792	192,024	164,653
Earnings from jointly controlled entities after interest and tax	8	3,083	1,818	826
Earnings from associates after interest and tax	8	460	462	388
Interest and other revenues	9	613	615	746
Total revenues		243,948	194,919	166,613
Gains on sale of businesses and fixed assets	10	1,538	1,685	1,895
Total revenues and other income		245,486	196,604	168,508
Purchases		163,026	128,055	111,190
Production and manufacturing expenses		21,592	17,330	14,130
Production and similar taxes	11	3,010	2,149	1,723
Depreciation, depletion and amortization	12	8,771	8,529	8,076
Impairment and losses on sale of businesses and fixed assets	13	468	1,390	1,801
Exploration expense	19	684	637	542
Distribution and administration expenses	15	13,706	12,768	12,270
Fair value (gain) loss on embedded derivatives	37	2,047		
Profit before interest and taxation from continuing operations		32,182	25,746	18,776
Finance costs	21	616	440	513
Other finance expense	22	145	340	532
Profit before taxation from continuing operations		31,421	24,966	17,731
Taxation	23	9,288	7,082	5,050
Profit from continuing operations		22,133	17,884	12,681
Profit (loss) from Innovene operations	5	184	(622)	(63)
Profit for the year		22,317	17,262	12,618
Attributable to				
BP shareholders		22,026	17,075	12,448
Minority interest		291	187	170
		22,317	17,262	12,618
Profit for the year attributable to BP shareholders*		22,026	17,075	12,448
Dividend requirements on preference shares*		2	2	2

Profit for the year applicable to ordinary shares*		22,024	17,073	12,446
Profit per ordinary share cents				
Basic	26	104.25	78.24	56.14
Diluted	26	103.05	76.87	55.61
Dividends announced and paid per ordinary share cents		34.85	27.70	25.50
Average number outstanding of 25 cents ordinary shares (in thousands)		21,125,902	21,820,535	22,170,741

* A summary of the adjustments to profit for the year attributable to BP shareholders which would be required if generally accepted accounting principles in the United States had been applied instead of International Financial Reporting Standards as adopted by the EU is given in Note 55.

The Notes to Financial Statements are an integral part of this Statement.

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BP p.l.c. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

	Note	December 31, 2005	2004	2003
		($ million)		
Noncurrent assets				
Property, plant and equipment	27	85,947	93,092	88,607
Goodwill	28	10,371	10,857	10,592
Intangible assets	29	4,772	4,205	4,471
Investments in jointly controlled entities	30	13,556	14,556	12,909
Investments in associates	31	6,217	5,486	4,868
Other investments	32	967	394	1,452
Fixed assets		121,830	128,590	122,899
Loans		821	811	852
Other receivables	34	770	429	495
Derivative financial instruments	37	3,652	898	534
Prepayments and accrued income		1,269	354	957
Defined benefit pension plan surplus	44	3,282	2,105	1,680
		131,624	133,187	127,417
Current assets				
Loans		132	193	182
Inventories	33	19,760	15,645	11,597
Trade and other receivables	34	40,902	37,099	27,881
Derivative financial instruments	37	9,726	5,317	1,891
Prepayments and accrued income		1,598	1,671	1,375
Current tax receivable		212	159	92
Cash and cash equivalents	35	2,960	1,359	2,056
		75,290	61,443	45,074
Total assets		206,914	194,630	172,491
Current liabilities				
Trade and other payables	36	42,136	38,540	29,740
Derivative financial instruments	37	9,083	5,074	4,145
Accruals and deferred income		5,970	4,482	2,266
Finance debt	41	8,932	10,184	9,456
Current tax payable		4,274	4,131	3,441
Provisions	43	1,602	715	735
		71,997	63,126	49,783
Noncurrent liabilities				

Other payables	36	1,935	3,581	4,630
Derivative financial instruments	37	3,696	158	344
Accruals and deferred income		3,164	699	864
Finance debt	41	10,230	12,907	12,869
Deferred tax liabilities	23	16,258	16,701	16,051
Provisions	43	9,954	8,884	7,864
Defined benefit pension plan and other postretirement benefit plan deficits	44	9,230	10,339	9,822
		54,467	53,269	52,444
Total liabilities		126,464	116,395	102,227
Net assets		80,450	78,235	70,264
Equity				
Share capital		5,185	5,403	5,552
Reserves		74,476	71,489	63,587
BP shareholders equity*		79,661	76,892	69,139
Minority interest		789	1,343	1,125
Total equity		80,450	78,235	70,264

* A summary of the adjustments to BP shareholders equity which would be required if generally accepted accounting principles in the United States had been applied instead of International Financial Reporting Standards as adopted by the EU is given in Note 55.

The Notes to Financial Statements are an integral part of this Balance Sheet.

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BP p.l.c. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CASH FLOWS

	Note	2005	2004	2003
		Years ended December 31,		
			($ million)	
Operating activities				
Profit before taxation from continuing operations		31,421	24,966	17,731
Adjustments to reconcile profits before tax to net cash provided by operating activities				
Exploration expenditure written off	19	305	274	297
Depreciation, depletion and amortization	12	8,771	8,529	8,076
Impairment and (gain) loss on sale of businesses and fixed assets	10, 13	(1,070)	(295)	(94)
Earnings from jointly controlled entities and associates	8	(3,543)	(2,280)	(1,214)
Dividends received from jointly controlled entities and associates		2,833	2,199	548
Interest receivable		(479)	(284)	(212)
Interest received		401	331	186
Finance costs	21	616	440	513
Interest paid		(1,127)	(698)	(1,007)
Other finance expense	22	145	340	532
Share-based payments		278	224	208
Net operating charge for pensions and other postretirement benefits, less contributions		(435)	(84)	(2,913)
Net charge for provisions, less payments		1,100	(110)	171
(Increase) decrease in inventories		(6,638)	(3,182)	(657)
(Increase) decrease in other current and noncurrent assets		(16,427)	(10,225)	(2,981)
Increase (decrease) in other current and noncurrent liabilities		18,628	10,290	1,575
Income taxes paid		(9,028)	(6,388)	(4,804)
Net cash provided by operating activities of continuing operations		25,751	24,047	15,955
Net cash provided by (used in) operating activities of Innovene operations	5	970	(669)	348
Net cash provided by operating activities		26,721	23,378	16,303
Investing activities				
Capital expenditures		(12,281)	(12,286)	(11,885)
Acquisitions, net of cash acquired		(60)	(1,503)	(211)
Investment in jointly controlled entities		(185)	(1,648)	(2,630)
Investment in associates		(619)	(942)	(987)
Proceeds from disposal of property, plant and equipment	6	2,803	4,236	6,177
Proceeds from disposal of businesses	6	8,397	725	179
Proceeds from loan repayments		123	87	76

Other		93		
Net cash used in investing activities		(1,729)	(11,331)	(9,281)
Financing activities				
Net repurchase of shares		(11,315)	(7,208)	(1,889)
Proceeds from long-term financing		2,475	2,675	4,322
Repayments of long-term financing		(4,820)	(2,204)	(3,560)
Net increase (decrease) in short-term debt		(1,457)	(24)	(2)
Dividends paid				
BP shareholders	25	(7,359)	(6,041)	(5,654)
Minority interest		(827)	(33)	(20)
Net cash used in financing activities		(23,303)	(12,835)	(6,803)
Currency translation differences relating to cash and cash equivalents		(88)	91	121
Increase (decrease) in cash and cash equivalents		1,601	(697)	340
Cash and cash equivalents at beginning of year		1,359	2,056	1,716
Cash and cash equivalents at end of year		2,960	1,359	2,056

The Notes to Financial Statements are an integral part of this Statement.

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BP p.l.c. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF RECOGNIZED INCOME AND EXPENSE

	Note	2005	2004	2003
		Years ended December 31,		
		($ million)		
Currency translation differences		(2,502)	2,283	3,656
Exchange gain on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets		(315)	(78)	
Actuarial gain relating to pensions and other postretirement benefits		975	107	76
Available-for-sale investments marked to market		322		
Available-for-sale investments recycled to the income statement		(60)		
Cash flow hedges marked to market		(212)		
Cash flow hedges recycled to the income statement		36		
Cash flow hedges recycled to the balance sheet				
Unrealized gain on acquisition of further investment in equity-accounted investments			94	
Tax on currency translation differences		11	(208)	(37)
Tax on exchange gain on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets		95		
Tax on actuarial gain (loss) relating to pensions and other postretirement benefits		(356)	96	(16)
Tax on available-for-sale investments		(72)		
Tax on cash flow hedges		63		
Tax on share-based payment accrual			39	5
Net income recognized directly in equity		(2,015)	2,333	3,684
Profit for the year		22,317	17,262	12,618
Total recognized income and expense relating to the year		20,302	19,595	16,302
Change in accounting policy adoption of IAS 32 and IAS 39 on January 1, 2005	52	(243)		
Total recognized income and expense since last annual accounts		20,059		
Attributable to				
BP shareholders		19,768	19,408	16,132
Minority interest		291	187	170
		20,059	19,595	16,302

The Notes to Financial Statements are an integral part of this Statement.

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BP p.l.c. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN BP SHAREHOLDERS EQUITY

The Company s authorized ordinary share capital at December 31, 2005, 2004 and 2003 was 36 billion shares of 25 cents each, amounting to $9 billion. In addition the Company has authorized preference share capital of 12,750,000 shares of £1 each ($21 million).

The allotted, called up and fully paid share capital at December 31, was as follows:

	Years ended December 31,					
	2005		2004		2003	
Issued	Shares (thousands)	($ million)	Shares (thousands)	($ million)	Shares (thousands)	($ million)
8% cumulative first preference shares of £1 each	7,233	12	7,233	12	7,233	12
9% cumulative second preference shares of £1 each	5,473	9	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each January 1,	21,525,978	5,382	22,122,610	5,531	22,378,651	5,595
Employee share schemes	68,500	17	62,224	16	32,889	8
Atlantic Richfield	13,644	3	29,288	7	9,786	2
Issue of ordinary share capital for TNK-BP	108,629	27	139,096	35		
Repurchase of ordinary share capital	(1,059,706)	(265)	(827,240)	(207)	(298,716)	(74)
December 31,	20,657,045	5,164	21,525,978	5,382	22,122,610	5,531
		5,185		5,403		5,552
Authorized						
8% cumulative first preference shares of £1 each	7,250		7,250		7,250	
9% cumulative second preference shares of £1 each	5,500		5,500		5,500	
Ordinary shares of 25 cents each	36,000,000		36,000,000		36,000,000	

(a) Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.
In the event of the winding up of the Company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

The Notes to Financial Statements are an integral part of this Statement.

BP p.l.c. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN BP SHAREHOLDERS EQUITY (Continued)

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Other reserve	Own shares	Treasury shares
			($ million)				
At December 31, 2004	5,403	5,636	730	27,162	44	(82)	
Adoption of IAS 39							
At January 1, 2005	5,403	5,636	730	27,162	44	(82)	
Currency translation differences (net of tax)						12	
Exchange gain on translation of foreign operations transferred to (profit) or loss on sale (net of tax)							
Actuarial gain (loss) (net of tax)							
Employee share schemes (a)	17	436					3
Atlantic Richfield (b)	3	76		28	(28)		
Issue of ordinary share capital for TNK-BP (c)	27	1,223					
Purchase of shares by ESOP trusts						(251)	
Available-for-sale investments marked to market (net of tax)							
Available-for-sale investments recycling (net of tax)							
Repurchase of ordinary share capital (d)	(265)		19				(10,601)
Share-based payments (net of tax) (e)						181	
Cash flow hedges marked to market (net of tax)							
Cash flow hedges recycling (net of tax)							
Profit for the year							
Dividends (f)							
At December 31, 2005	5,185	7,371	749	27,190	16	(140)	(10,598)
At January 1, 2004	5,552	3,957	523	27,077	129	(96)	
Currency translation differences (net of tax)						(7)	
Exchange gain on translation of foreign operations transferred to (profit) or loss on sale (net of tax)							
Actuarial gain (loss) (net of tax)							
Unrealized gain on acquisition of further investment in							

equity-accounted investments						
Employee share schemes (a)	16	311				
Atlantic Richfield (b)	7	153		85	(85)	
Issue of ordinary share capital for TNK-BP (c)	35	1,215				
Purchase of shares by ESOP trusts						(147)
Repurchase of ordinary share capital (d)	(207)		207			
Share-based payments (net of tax) (e)						168
Profit for the year						
Dividends (f)						
At December 31, 2004	5,403	5,636	730	27,162	44	(82)
At January 1, 2003	5,616	3,794	449	27,033	173	(159)
Currency translation differences (net of tax)						(8)
Actuarial gain (loss) (net of tax)						
Employee share schemes (a)	8	127				
Atlantic Richfield (b)	2	36		44	(44)	
Purchase of shares by ESOP trusts						(63)
Repurchase of ordinary share capital (d)	(74)		74			
Share-based payments (net of tax) (e)						134
Increased minority participation						
Profit for the year						
Dividends (f)						
At December 31, 2003	5,552	3,957	523	27,077	129	(96)

BP p.l.c. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CHANGES IN BP SHAREHOLDERS EQUITY (Continued)

Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Retained earnings (g)	BP shareholders equity	Minority interest	Total equity
			($ million)			
5,616			32,383	76,892	1,343	78,235
	230	(118)	(355)	(243)		(243)
5,616	230	(118)	32,028	76,649	1,343	77,992
(2,453)	(35)	(3)		(2,479)	(18)	(2,497)
(220)				(220)		(220)
			619	619		619
			(1)	455		455
				79		79
				1,250		1,250
				(251)		(251)
	232			232		232
	(42)			(42)		(42)
			(750)	(11,597)		(11,597)
			231	412		412
		(149)		(149)		(149)
		36		36		36
			22,026	22,026	291	22,317
			(7,359)	(7,359)	(827)	(8,186)
2,943	385	(234)	46,794	79,661	789	80,450
3,619			28,378	69,139	1,125	70,264
2,075				2,068	64	2,132
(78)				(78)		(78)
			203	203		203
			94	94		94

		327		327
		160		160
		1,250		1,250
		(147)		(147)
	(7,548)	(7,548)		(7,548)
	222	390		390
	17,075	17,075	187	17,262
	(6,041)	(6,041)	(33)	(6,074)
5,616	32,383	76,892	1,343	78,235
	23,323	60,229	638	60,867
3,619		3,611	20	3,631
	60	60		60
		135		135
		38		38
		(63)		(63)
	(1,999)	(1,999)		(1,999)
	200	334		334
			317	317
	12,448	12,448	170	12,618
	(5,654)	(5,654)	(20)	(5,674)
3,619	28,378	69,139	1,125	70,264

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BP p.l.c. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN BP SHAREHOLDERS EQUITY (Continued)

Share capital. The balance on the share capital account represents the aggregate nominal value of all ordinary and preference shares in issue.

Share premium account. The balance on the share premium account represents the amounts received in excess of the nominal value of the ordinary and preference shares.

Capital redemption reserve. The balance on the capital redemption reserve represents the aggregate nominal value of all the ordinary shares repurchased and cancelled.

Merger reserve. The balance on the merger reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares.

Other reserve. The balance on the other reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares to be issued in the ARCO acquisition on the exercise of ARCO share options.

Own shares. Own shares represent BP shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment arrangements.

Treasury shares. Treasury shares represent BP shares repurchased and available for issue.

Foreign currency translation reserve. The foreign currency translation reserve is used to record exchange differences arising from the translations of the financial statements of foreign operations. It is also used to record the effect of hedging net investments in foreign operations.

Available-for-sale investments. This reserve records the changes in fair value on available-for-sale investments. On disposal, the cumulative changes in fair value are recycled to the income statement.

Cash flow hedges. This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. On maturity, the cumulative gain or loss is recycled to the income statement or balance sheet as appropriate.

Retained earnings. The balance held on this reserve is the accumulated retained profits of the Group.

(a) Employee share schemes. During the year 68,499,852 ordinary shares (2004 62,224,092 and 2003 32,889,234 ordinary shares) were issued under the BP, Amoco and Burmah Castrol employee share schemes.

(b) Atlantic Richfield. During the year 13,644,462 ordinary shares (2004 29,288,178 and 2003 9,786,396 ordinary shares) were issued in respect of Atlantic Richfield employee share option schemes.

(c) Issue of ordinary share capital for TNK-BP. During the year the company issued 108,628,984 ordinary shares (2004 139,095,888 ordinary shares) as the second (2004 first) tranche of deferred consideration for the acquisition of the investment in TNK-BP.

(d) Repurchase of ordinary share capital. During the year the company purchased 1,059,706,481 ordinary shares (2004 827,240,360 and 2003 298,716,391 ordinary shares) for a total consideration of $11,597 million (2004 $7,548 million and 2003 $1,999 million), of which 76,800,000 were cancelled and 982,906,481 were retained in treasury. All the shares repurchased in 2004 and 2003 were cancelled. At December 31, 2005, 982,624,971 shares of nominal value $246 million were held in treasury. Transaction costs of share repurchases amounted to $63 million (2004 $43 million and 2003 $11 million).

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BP p.l.c. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN BP SHAREHOLDERS   EQUITY (Concluded)

(e) See Note 46 Share-based payments.

(f) See Note 25 Dividends.

(g) See Note 45 Retained earnings.

The Notes to Financial Statements are an integral part of this Statement.

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS

Note 1 Significant accounting policies

Presentation of financial information

The consolidated financial statements for the year ended December 31, 2005 were authorized on June 30, 2006. BP p.l.c. is a public limited company incorporated and domiciled in England and Wales. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards as adopted by the European Union (IFRS). International Financial Reporting Standards as adopted by the European Union differ in certain respects from International Financial Reporting Standards as issued by the International Accounting Standards Board (IASB). However, the consolidated financial statements for the years presented would be no different had the Group applied International Financial Reporting Standards as issued by the IASB.

Basis of preparation

This is the first year in which the Group has prepared its financial statements under IFRS and the comparative financial information has been restated from UK generally accepted accounting practice (UK GAAP) to comply with IFRS. Reconciliations to IFRS from the previously published UK GAAP primary financial statements are shown in Note 52. The accounting policies that follow set out those policies that apply in preparing the consolidated financial statements for the year ended December 31, 2005. The consolidated financial statements are presented in US dollars and all values are rounded to the nearest million dollars ($ million), except where otherwise indicated.

Basis of consolidation

The Group financial statements consolidate the financial statements of BP p.l.c. and the entities it controls (its subsidiaries) drawn up to December 31 each year. Control comprises the power to govern the financial and operating policies of the investee so as to obtain benefit from its activities and is achieved through direct and indirect ownership of voting rights; currently exercisable or convertible potential voting rights; or by way of contractual agreement. Subsidiaries are consolidated from the date of their acquisition, being the date on which the Group obtains control, and continue to be consolidated until the date that such control ceases. The financial statements of subsidiaries are prepared for the same reporting year as the parent company, using consistent accounting policies. All intercompany balances and transactions, including unrealized profits arising from intragroup transactions, have been eliminated in full. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred. Minority interests represent the portion of profit or loss and net assets in subsidiaries that is not held by the Group and is presented separately within equity in the consolidated balance sheet.

Interests in joint ventures

A joint venture is a contractual arrangement whereby two or more parties (venturers) undertake an economic activity that is subject to joint control. Joint control exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the venturers. A jointly controlled entity is a joint venture that involves the establishment of a company, partnership or other entity to engage in economic activity that the Group jointly controls with its fellow venturers.

The results, assets and liabilities of a jointly controlled entity are incorporated in these financial statements using the equity method of accounting. Under the equity method, the investment in a jointly controlled entity is carried in the balance sheet at cost, plus post-acquisition changes in the Group s share of net assets of the jointly controlled entity, less distributions received and less any impairment in

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

value of the investment. The Group income statement reflects the Group s share of the results after tax of the jointly controlled entity. The Group statement of recognized income and expense reflects the Group s share of any income and expense recognized by the jointly controlled entity outside profit and loss.

Financial statements of jointly controlled entities are prepared for the same reporting year as the Group. Where necessary, adjustments are made to those financial statements to bring the accounting policies used into line with those of the Group.

Unrealized gains on transactions between the Group and its jointly controlled entities are eliminated to the extent of the Group s interest in the jointly controlled entities. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The Group ceases to use the equity method of accounting on the date from which it no longer has joint control over, or significant influence in the joint venture, or when the interest becomes held for sale.

Certain of the Group s activities, particularly in the Exploration and Production segment, are conducted through joint ventures where the venturers have a direct ownership interest in and jointly control the assets of the venture. The income, expenses, assets and liabilities of these jointly controlled assets are included in the consolidated financial statements in proportion to the Group s interest.

Interests in associates

An associate is an entity over which the Group is in a position to exercise significant influence through participation in the financial and operating policy decisions of the investee, but which is not a subsidiary or a jointly controlled entity.

The results, assets and liabilities of an associate are incorporated in these financial statements using the equity method of accounting. Under the equity method, the investment in an associate is carried in the balance sheet at cost, plus post-acquisition changes in the Group s share of net assets of the associate, less distributions received and less any impairment in value of the investment. The Group income statement reflects the Group s share of the results after tax of the associate. The Group statement of recognized income and expense reflects the Group s share of any income and expense recognized by the associate outside profit and loss.

The financial statements of associates are prepared for the same reporting year as the Group. Where necessary, adjustments are made to those financial statements to bring the accounting policies used into line with those of the Group.

Unrealized gains on transactions between the Group and its associates are eliminated to the extent of the Group s interest in the associates. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The Group ceases to use the equity method of accounting on the date from which it no longer has significant influence in the associate or when the interest becomes held for sale.

Foreign currency translation

In individual companies, transactions in foreign currencies are initially recorded in the functional currency by applying the rate of exchange ruling at the date of the transaction. Monetary assets and

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

liabilities denominated in foreign currencies are translated into the functional currency at the rate of exchange ruling at the balance sheet date. Any resulting exchange differences are included in the income statement. Nonmonetary assets and liabilities that are measured in terms of historical cost in a foreign currency are translated into the functional currency using the rates of exchange as at the dates of the initial transactions. Nonmonetary assets and liabilities measured at fair value in a foreign currency are translated into the functional currency using the rate of exchange at the date the fair value was determined.

In the consolidated financial statements, the assets and liabilities of non-US dollar functional currency subsidiaries, jointly controlled entities and associates, including related goodwill, are translated into US dollars at the rate of exchange ruling at the balance sheet date. The results and cash flows of non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars using average rates of exchange. Exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars are taken to a separate component of equity and reported in the statement of recognized income and expense. Exchange gains and losses arising on long-term foreign currency borrowings used to finance the Group s non-US dollar investments are also taken to equity. On disposal of a non-US dollar functional currency subsidiary, jointly controlled entity or associate, the deferred cumulative amount recognized in equity relating to that particular non-US dollar operation is recognized in the income statement.

Business combinations and goodwill

Business combinations are accounted for using the acquisition method of accounting. The cost of an acquisition is measured as the cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange, plus costs directly attributable to the acquisition. The acquired identifiable assets, liabilities and contingent liabilities are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the net fair value of the identifiable assets acquired is recognized as goodwill. Any deficiency of the cost of acquisition below the fair values of the identifiable net assets acquired (i.e. discount on acquisition) is credited to the income statement in the period of acquisition. Where the Group does not acquire 100% ownership of the acquired company, the interest of minority shareholders is stated at the minority s proportion of the fair values of the assets and liabilities recognized. Subsequently, any losses applicable to the minority shareholders in excess of the minority interest are allocated against the interests of the parent.

Goodwill on acquisition is initially measured at cost being the excess of the cost of the business combination over the acquirer s interest in the net fair value of the identifiable assets, liabilities and contingent liabilities. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired.

As at the acquisition date, any goodwill acquired is allocated to each of the cash-generating units expected to benefit from the combination s synergies. For this purpose, cash-generating units are set at one level below a business segment. Impairment is determined by assessing the recoverable amount of the cash-generating unit to which the goodwill relates. Where the recoverable amount of the cash-generating unit is less than the carrying amount, an impairment loss is recognized.

Goodwill arising on business combinations prior to January 1, 2003 is stated at the previous UK GAAP carrying amount.

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

Goodwill may also arise upon investments in jointly controlled entities and associates, being the surplus of the cost of investment over the Group s share of the net fair value of the identifiable assets. Such goodwill is recorded within investments in jointly controlled entities and associates, and any impairment of the goodwill is included within the income from jointly controlled entities and associates.

Noncurrent assets held for sale

Noncurrent assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell.

Noncurrent assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification.

Property, plant and equipment and intangible assets once classified as held for sale are not depreciated.

Intangible assets

Intangible assets are stated at cost, less accumulated amortization and accumulated impairment losses. Intangible assets include expenditure on the exploration for and evaluation of oil and natural gas resources, computer software, patents, licences, trademarks and product development costs.

Intangible assets acquired separately from a business are carried initially at cost. The initial cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. An intangible asset acquired as part of a business combination is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights and its fair value can be measured reliably.

Product development costs are capitalized as intangible assets when a project has obtained internal sanction and the future recoverability of such costs can reasonably be regarded as assured.

Intangible assets with a finite life are amortized on a straight-line basis over their expected useful lives. For patents, licences and trademarks, expected useful life is the lower of the duration of the legal agreement and economic useful life, which can range from three to 15 years. Computer software costs have a useful life of three to five years.

The expected useful lives of the assets are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying value of intangible assets is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. In addition, the carrying value of capitalized product development expenditure is reviewed for impairment annually before being brought into use.

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

Oil and natural gas exploration and development expenditure

Oil and natural gas exploration and development expenditure is accounted for using the successful efforts method of accounting.

Licence and property acquisition costs. Exploration and property leasehold acquisition costs are capitalized within intangible fixed assets and amortized on a straight-line basis over the estimated period of exploration. Each property is reviewed on an annual basis to confirm that drilling activity is planned and it is not impaired. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Upon determination of economically recoverable reserves (proved reserves or commercial reserves), amortization ceases and the remaining costs are aggregated with exploration expenditure and held on a field-by-field basis as proved properties awaiting approval within other intangible assets. When development is approved internally, the relevant expenditure is transferred to property, plant and equipment.

Exploration expenditure. Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to property, plant and equipment.

Development expenditure. Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, is capitalized within property, plant and equipment.

Property, plant and equipment

Property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning obligation, if any, and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included within property, plant and equipment.

Exchanges of assets are measured at the fair value of the asset given up unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated and is now written off is replaced and it is probable that future economic

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

benefits associated with the item will flow to the Group, the expenditure is capitalized. Inspection costs associated with major maintenance programmes are capitalized and amortized over the period to the next inspection. Overhaul costs for major maintenance programmes are expensed as incurred. All other maintenance costs are expensed as incurred.

Oil and natural gas properties are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, decommissioning and field development costs are amortized over total proved reserves. The unit-of-production rate for the amortization of field development costs takes into account expenditures incurred to date, together with sanctioned future development expenditure.

Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life.

The useful lives of the Group s other property, plant and equipment are as follows:

Land improvements	15 to 25 years
Buildings	20 to 40 years
Refineries	20 to 30 years
Petrochemicals plants	20 years
Pipelines	Unit-of-throughput 10 to 50 years
Service stations	15 years
Office equipment	3 to 7 years
Fixtures and fittings	5 to 15 years

The expected useful lives of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying value of property, plant and equipment is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable.

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period the item is derecognized.

Impairment of intangible assets and property, plant and equipment

The Group assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. If any such indication of impairment exists or when annual impairment testing for an asset group is required, the Group makes an estimate of its recoverable amount. An asset group s recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset s recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Such reversal is recognized in profit or loss. After such a reversal, the depreciation charge is adjusted in future periods to allocate the asset s revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Financial assets

Financial assets are classified as financial assets at fair value through profit or loss; loans and receivables; held-to-maturity investments; or as available-for-sale financial assets, as appropriate. Financial assets include cash and cash equivalents; trade receivables; other receivables; loans; other investments; and derivative financial instruments. The Group determines the classification of its financial assets at initial recognition. When financial assets are recognized initially, they are measured at fair value, normally being the transaction price plus, in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs. As explained in Note 52, the Group has not restated comparative amounts, on first applying IAS 32 Financial Instruments: Disclosure and Presentation and IAS 39 Financial Instruments: Recognition and Measurement , as permitted in IFRS 1 First-time Adoption of International Financial Reporting Standards .

All regular way purchases and sales of financial assets are recognized on the trade date, being the date that the Group commits to purchase or sell the asset. Regular way transactions require delivery of assets within the timeframe generally established by regulation or convention in the marketplace. The subsequent measurement of financial assets depends on their classification, as follows:

Financial assets at fair value through profit or loss. Financial assets classified as held for trading and other assets designated as such on inception are included in this category. Financial assets are classified as held for trading if they are acquired for sale in the short term. Derivatives are also classified as held for trading unless they are designated as hedging instruments. Assets are carried on the balance sheet at fair value with gains or losses recognized in the income statement.

Loans and receivables. Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market, do not qualify as trading assets and have not been designated as either fair value through profit and loss or available-for-sale. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired, as well as through the amortization process.

Held-to-maturity investments. Non-derivative financial assets with fixed or determinable payments and fixed maturity are classified as held-to-maturity when the Group has the positive intention and ability to hold to maturity. Held-to-maturity investments are carried at amortized cost using the effective interest method. Gains and losses are recognized in income when the investments are derecognized or

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

impaired, as well as through the amortization process. Investments intended to be held for an undefined period are not included in this classification.

Available-for-sale financial assets. Available-for-sale financial assets are those non-derivative financial assets that are designated as such or are not classified in any of the three preceding categories. After initial recognition, available-for-sale financial assets are measured at fair value, with gains or losses being recognized as a separate component of equity until the investment is derecognized or until the investment is determined to be impaired, at which time the cumulative gain or loss previously reported in equity is included in the income statement.

Fair values. The fair value of quoted investments is determined by reference to bid prices at the close of business on the balance sheet date. Where there is no active market, fair value is determined using valuation techniques. These include using recent arm s-length market transactions; reference to the current market value of another instrument which is substantially the same; discounted cash flow analysis; and pricing models. Otherwise assets are carried at cost.

Impairment of financial assets

The Group assesses at each balance sheet date whether a financial asset or group of financial assets is impaired.

Assets carried at amortized cost. If there is objective evidence that an impairment loss on loans and receivables carried at amortized cost has been incurred, the amount of the loss is measured as the difference between the asset s carrying amount and the present value of estimated future cash flows discounted at the financial asset s original effective interest rate. The carrying amount of the asset is reduced, with the amount of the loss recognized in administration costs.

If, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized, the previously recognized impairment loss is reversed. Any subsequent reversal of an impairment loss is recognized in the income statement, to the extent that the carrying value of the asset does not exceed its amortized cost at the reversal date.

Assets carried at cost. If there is objective evidence that an impairment loss on an unquoted equity instrument that is not carried at fair value because its fair value cannot be reliably measured, or on a derivative asset that is linked to and must be settled by delivery of such an unquoted equity instrument, has been incurred, the amount of the loss is measured as the difference between the asset s carrying amount and the present value of estimated future cash flows discounted at the current market rate of return for a similar financial asset.

Available-for-sale financial assets. If an available-for-sale asset is impaired, an amount comprising the difference between its cost (net of any principal payment and amortization) and its fair value is transferred from equity to the income statement.

Reversals of impairment losses on debt instruments are taken through the income statement if the increase in fair value of the instrument can be objectively related to an event occurring after the impairment loss was recognized in profit or loss. Reversals in respect of equity instruments classified as available-for-sale are not recognized in the income statement.

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

Inventories

Inventories, other than inventory held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses.

Inventories held for trading purposes are stated at fair value less costs to sell and any changes in net realizable value are recognized in the income statement.

Supplies are valued at cost to the Group mainly using the average method or net realizable value, whichever is the lower.

Trade and other receivables

Trade and other receivables are carried at the original invoice amount, less allowances made for doubtful receivables. Where the time value of money is material, receivables are carried at amortized cost. Provision is made when there is objective evidence that the Group will be unable to recover balances in full. Balances are written off when the probability of recovery is assessed as being remote.

Cash and cash equivalents

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and have a maturity of three months or less from the date of acquisition.

For the purpose of the Group cash flow statement, cash and cash equivalents consist of cash and cash equivalents as defined above, net of outstanding bank overdrafts.

Trade and other payables

Trade and other payables are carried at payment or settlement amounts. Where the time value of money is material, payables are carried at amortized cost.

Interest-bearing loans and borrowings

All loans and borrowings are initially recognized at cost, being the fair value of the proceeds received net of issue costs associated with the borrowing.

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs, and any discount or premium on settlement.

Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized respectively in interest and other revenues and other finance expense.

Leases

Finance leases, which transfer to the Group substantially all the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Lease payments are apportioned between the finance charges and reduction of the lease liability so as to achieve a constant

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

rate of interest on the remaining balance of the liability. Finance charges are charged directly against income.

Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Operating lease payments are recognized as an expense in the income statement on a straight-line basis over the lease term.

Derecognition of financial assets and liabilities

Financial assets. A financial asset (or, where applicable, a part of a financial asset or part of a group of similar financial assets) is derecognized where:

The rights to receive cash flows from the asset have expired;

The Group retains the right to receive cash flows from the asset, but has assumed an obligation to pay them in full without material delay to a third party under a pass-through arrangement; or

The Group has transferred its rights to receive cash flows from the asset and either (a) has transferred substantially all the risks and rewards of the asset or (b) has neither transferred nor retained substantially all the risks and rewards of the asset but has transferred control of the asset.

Where the Group has transferred its rights to receive cash flows from an asset and has neither transferred nor retained substantially all the risks and rewards of the asset nor transferred control of the asset, the asset is recognized to the extent of the Group s continuing involvement in the asset. Continuing involvement that takes the form of a guarantee over the transferred asset is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that the Group could be required to repay.

Where continuing involvement takes the form of a written and/or purchased option (including a cash-settled option or similar provision) on the transferred asset, the extent of the Group s continuing involvement is the amount of the transferred asset that the Group may repurchase, except that in the case of a written put option (including a cash-settled option or similar provision) on an asset measured at fair value, the extent of the Group s continuing involvement is limited to the lower of the fair value of the transferred asset and the option exercise price.

Financial liabilities. A financial liability is derecognized when the obligation under the liability is discharged, cancelled or expires. Where an existing financial liability is replaced by another from the same lender on substantially different terms or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability, such that the difference in the respective carrying amounts, together with any costs or fees incurred are recognized in profit or loss.

Derivative financial instruments

The Group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices. From January 1, 2005, such derivative financial instruments are initially recognized at fair value on the date on which a derivative

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Contracts to buy or sell a nonfinancial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments, as if the contracts were financial instruments, with the exception of contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a nonfinancial item in accordance with the Group s expected purchase, sale or usage requirements, are financial instruments.

For those derivatives designated as hedges and for which hedge accounting is desired, the hedging relationship is documented at its inception. This documentation identifies the hedging instrument, the hedged item or transaction, the nature of the risk being hedged and how effectiveness will be measured throughout its duration. Such hedges are expected at inception to be highly effective.

For the purpose of hedge accounting, hedges are classified as:

Fair value hedges when hedging the exposure to changes in the fair value of a recognized asset or liability;

Cash flow hedges when hedging exposure to variability in cash flows that is either attributable to a particular risk associated with a recognized asset or liability or a highly probable forecast transaction, including intra-group transactions; or

Hedges of the net investment in a foreign entity.

Any gains or losses arising from changes in the fair value of all other derivatives, which are classified as held for trading, are taken to the income statement. These may arise from derivatives for which hedge accounting is not applied because they are either not designated or not effective as hedging instruments or from derivatives that are acquired for trading purposes.

The treatment of gains and losses arising from revaluing derivatives designated as hedging instruments depends on the nature of the hedging relationship, as follows:

Fair value hedges. For fair value hedges, the carrying amount of the hedged item is adjusted for gains and losses attributable to the risk being hedged; the derivative is remeasured at fair value and gains and losses from both are taken to profit or loss. For hedged items carried at amortized cost, the adjustment is amortized through the income statement such that it is fully amortized by maturity. When an unrecognized firm commitment is designated as a hedged item, this gives rise to an asset or liability in the balance sheet, representing the cumulative change in the fair value of the firm commitment attributable to the hedged risk.

The Group discontinues fair value hedge accounting if the hedging instrument expires or is sold, terminated or exercised, the hedge no longer meets the criteria for hedge accounting or the Group revokes the designation.

Cash flow hedges. For cash flow hedges, the effective portion of the gain or loss on the hedging instrument is recognized directly in equity, while the ineffective portion is recognized in profit or loss. Amounts taken to equity are transferred to the income statement when the hedged transaction affects profit or loss, such as when a forecast sale or purchase occurs. Where the hedged item is the cost of a nonfinancial asset or liability, the amounts taken to equity are transferred to the initial carrying amount of the nonfinancial asset or liability.

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

If the hedging instrument expires or is sold, terminated or exercised without replacement or rollover, the hedged transaction ceases to be highly probable, or if its designation as a hedge is revoked, amounts previously recognized in equity remain in equity until the forecast transaction occurs and are transferred to the income statement or to the initial carrying amount of a nonfinancial asset or liability as above. If a forecast transaction is no longer expected to occur, amounts previously recognized in equity are transferred to profit or loss.

Hedges of the net investment in a foreign entity. For hedges of the net investment in a foreign entity, the effective portion of the gain or loss on the hedging instrument is recognized directly in equity, while the ineffective portion is recognized in profit or loss. Amounts taken to equity are transferred to the income statement when the foreign entity is sold.

Embedded derivatives. Derivatives embedded in other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of host contracts and the host contracts are not carried at fair value. Contracts are assessed for embedded derivatives when the Group becomes a party to them, including at the date of a business combination. These embedded derivatives are measured at fair value at each period end. Any gains or losses arising from changes in fair value are taken directly to net profit or loss for the period.

Provisions

Provisions are recognized when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Group expects some or all of a provision to be reimbursed, for example, under an insurance contract, the reimbursement is recognized as a separate asset, but only when the reimbursement is virtually certain. The expense relating to any provision is presented in the income statement net of any reimbursement. If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognized as other finance expense. Any change in the amount recognized for environmental and litigation and other provisions arising through changes in discount rates is included within other finance expense.

A contingent liability is disclosed where the existence of an obligation will only be confirmed by future events or where the amount of the obligation cannot be measured with reasonable reliability. Contingent assets are not recognized, but are disclosed where an inflow of economic benefits is probable.

Environmental liabilities

Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future earnings are expensed.

Liabilities for environmental costs are recognized when environmental assessments or clean-ups are probable and the associated costs can be reasonably estimated. Generally, the timing of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

The amount recognized is the best estimate of the expenditure required. Where the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure.

Decommissioning

Liabilities for decommissioning costs are recognized when the Group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reasonable estimate of that liability can be made. Where an obligation exists for a new facility, such as oil and natural gas production or transportation facilities, this will be on construction or installation. An obligation for decommissioning may also crystallize during the period of operation of a facility through a change in legislation or through a decision to terminate operations. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements.

A corresponding item of property, plant and equipment of an amount equivalent to the provision is also created. This is subsequently depreciated as part of the capital costs of the facility or item of plant.

Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding property, plant and equipment.

Employee benefits

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of the Group. Deferred bonus arrangements that have a vesting date more than 12 months after the period end are valued on an actuarial basis using the projected unit credit method and amortized on a straight-line basis over the service period until the award vests. The accounting policy for pensions and other postretirement benefits is described below.

Share-based payments

Equity-settled transactions. The cost of equity-settled transactions with employees is measured by reference to the fair value at the date at which they are granted and is recognized as an expense over the vesting period, which ends on the date on which the relevant employees become fully entitled to the award. Fair value is determined by using an appropriate valuation model. In valuing equity-settled transactions, no account is taken of any vesting conditions, other than conditions linked to the price of the shares of the Company (market conditions).

No expense is recognized for awards that do not ultimately vest, except for awards where vesting is conditional upon a market condition, which are treated as vesting irrespective of whether or not the market condition is satisfied, provided that all other performance conditions are satisfied.

At each balance sheet date before vesting, the cumulative expense is calculated, representing the extent to which the vesting period has expired and management s best estimate of the achievement or otherwise of non-market conditions and the number of equity instruments that will ultimately vest or, in the case of an instrument subject to a market condition, be treated as vesting as described above. The movement in cumulative expense since the previous balance sheet date is recognized in the income statement, with a corresponding entry in equity.

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

Where the terms of an equity-settled award are modified or a new award is designated as replacing a cancelled or settled award, the cost based on the original award terms continues to be recognized over the original vesting period. In addition, an expense is recognized over the remainder of the new vesting period for the incremental fair value of any modification, based on the difference between the fair value of the original award and the fair value of the modified award, both as measured on the date of the modification. No reduction is recognized if this difference is negative.

Where an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation and any cost not yet recognized in the income statement for the award is expensed immediately. Any compensation paid up to the fair value of the award at the cancellation or settlement date is deducted from equity, with any excess over fair value being treated as an expense in the income statement.

Cash-settled transactions. The cost of cash-settled transactions is measured at fair value using an appropriate option valuation model. Fair value is established initially at the grant date and at each balance sheet date thereafter until the awards are settled. During the vesting period, a liability is recognized representing the product of the fair value of the award and the portion of the vesting period expired as at the balance sheet date. From the end of the vesting period until settlement, the liability represents the full fair value of the award as at the balance sheet date. Changes in the carrying amount for the liability are recognized in profit or loss for the period.

Pensions and other postretirement benefits

The cost of providing benefits under the defined benefit plans is determined separately for each plan using the projected unit method, which attributes entitlement to benefits to the current period (to determine current service cost) and to the current and prior periods (to determine the present value of defined benefit obligation) and is based on actuarial advice. Past service costs are recognized in profit or loss on a straight-line basis over the vesting period or immediately if the benefits have vested. When a settlement (eliminating all obligations for benefits already accrued) or a curtailment (reducing future obligations as a result of a material reduction in the scheme membership or a reduction in future entitlement) occurs, the obligation and related plan assets are remeasured using current actuarial assumptions and the resultant gain or loss recognized in the income statement during the period in which the settlement or curtailment occurs.

The interest element of the defined benefit cost represents the change in present value of scheme obligations resulting from the passage of time, and is determined by applying the discount rate to the opening present value of the benefit obligation, taking into account material changes in the obligation during the year. The expected return on plan assets is based on an assessment made at the beginning of the year of long-term market returns on scheme assets, adjusted for the effect on the fair value of plan assets of contributions received and benefits paid during the year. The difference between the expected return on plan assets and the interest cost is recognized in the income statement as other finance income or expense.

Actuarial gains and losses are recognized in full in the Group statement of recognized income and expense in the period in which they occur.

The defined benefit pension asset or liability in the balance sheet comprises the total for each plan of the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds), less any past service cost not yet recognized and less the fair value of plan assets out

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price. The value of a net pension benefit asset is restricted to the sum of any unrecognized past service costs and the present value of any amount the Group expects to recover by way of refunds from the plan or reductions in the future contributions.

Contributions to defined contribution schemes are recognized in the income statement in the period in which they become payable.

Corporate taxes

Tax expense represents the sum of the tax currently payable and deferred tax.

The tax currently payable is based on the taxable profits for the period. Taxable profit differs from net profit as reported in the income statement because it excludes items of income or expense that are taxable or deductible in other periods and it further excludes items that are never taxable or deductible. The Group s liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is provided, using the liability method, on all temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax liabilities are recognized for all taxable temporary differences:

Except where the deferred tax liability arises on goodwill that is not tax deductible or the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and

In respect of taxable temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, except where the timing of the reversal of the temporary differences can be controlled by the Group and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for all deductible temporary differences, carry-forward of unused tax assets and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax assets and unused tax losses can be utilized:

Except where the deferred income tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and

In respect of deductible temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, deferred tax assets are only recognized to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred income tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred income tax asset to be utilized.

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date.

Tax relating to items recognized directly in equity is recognized in equity and not in the income statement.

Customs duties and sales taxes

Revenues, expenses and assets are recognized net of the amount of customs duties or sales tax except:

Where the customs duty or sales tax incurred on a purchase of goods and services is not recoverable from the taxation authority, in which case the customs duty or sales tax is recognized as part of the cost of acquisition of the asset or as part of the expense item as applicable; and

Receivables and payables are stated with the amount of customs duty or sales tax included.

The net amount of sales tax recoverable from, or payable to, the taxation authority is included as part of receivables or payables in the balance sheet.

Own equity instruments

The Group s holding in its own equity instruments, including shares held by Employee Share Ownership Plans (ESOPs), are classified as treasury shares , and shown as deductions from shareholders equity at cost. Consideration received for the sale of such shares is also recognized in equity, with any difference between the proceeds from sale and the original cost being taken to revenue reserves. No gain or loss is recognized in the performance statements on the purchase, sale, issue or cancellation of equity shares.

Revenue

Revenue arising from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer and it can be reliably measured. Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods provided in the normal course of business, net of discounts, customs duties and sales taxes.

Revenues associated with the sale of oil, natural gas liquids, liquefied natural gas, petroleum and chemicals products and all other items are recognized when the title passes to the customer. Supply buy/sell arrangements with common counterparties are reported net as are physical exchanges. Similarly, realized and unrealized gains and losses on exchange traded and over-the-counter commodity derivative contracts held for trading purposes and sales/purchases of trading inventory are included on a net basis in sales and other operating revenues. Generally, revenues from the production of oil and natural gas properties in which the Group has an interest with other producers are recognized on the basis of the Group s working interest in those properties (the entitlement method). Differences between the production sold and the Group s share of production are not significant.

Interest income is recognized as the interest accrues (using the effective interest rate method that is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument) to the net carrying amount of the financial asset.

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

Dividend income from investments is recognized when the shareholders right to receive the payment is established.

Note 1 Significant accounting policies (continued)

Research

Research costs are expensed as incurred.

Finance costs

Finance costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use.

All other finance costs are recognized in the income statement in the period in which they are incurred.

Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from those estimates.

Impact of new International Financial Reporting Standards

In August 2005, the IASB issued IFRS 7 Financial Instruments Disclosures which is effective for annual periods beginning on or after January 1, 2007, with earlier adoption encouraged. This standard has been adopted by the EU. Upon adoption, the Group will disclose additional information about its financial instruments, their significance and the nature and extent of risks to which they give rise. More specifically, the Group will be required to disclose the fair value of its financial instruments and its risk exposure in greater detail. There will be no effect on reported income or net assets. No decision has been made on whether to early adopt this standard.

Also in August 2005, IAS 1 Amendment Presentation of Financial Statements: Capital Disclosures was issued by the IASB, which requires disclosures of an entity s objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements, and the consequences of any non-compliance. This is effective for annual periods beginning on or after January 1, 2007. This standard has been adopted by the EU. There will be no effect on the Group s reported income or net assets.

IAS 21 Amendment Net Investment in a Foreign Operation was issued in December 2005. The amendment clarifies the requirements of IAS 21 The Effects of Changes in Foreign Exchange Rates regarding an entity s investment in foreign operations. This amendment is effective for annual periods beginning on or after January 1, 2006, and was adopted by the European Union (EU) in May 2006. There will be no material impact on the Group s reported income or net assets as a result of adoption of this amendment.

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Significant accounting policies (continued)

The IASB issued an amendment to the fair value option in IAS 39 Financial Instruments: Recognition and Measurement in June 2005. The option to irrevocably designate, on initial recognition, any financial instruments as ones to be measured at fair value with gains and losses recognized in profit and loss has now been restricted to those financial instruments meeting certain criteria. The criteria are where such designation eliminates or significantly reduces an accounting mismatch, when a group of financial assets, financial liabilities or both are managed and their performance is evaluated on a fair value basis in accordance with a documented risk management or investment strategy, and when an instrument contains an embedded derivative that meets particular conditions. The Group has not designated any financial instruments as being at-fair-value-through-profit-and-loss, thus there will be no effect on the Group s reported income or net assets as a result of adoption of this amendment.

In August 2005, the IASB issued amendments to IAS 39 Financial Instruments: Recognition and Measurement and IFRS 4 Insurance Contracts regarding Financial Guarantee Contracts . These amendments require the issuer of financial guarantee contracts to account for them under IAS 39 as opposed to IFRS 4 unless an issuer has previously asserted explicitly that it regards such contracts as insurance contracts and has used accounting applicable to insurance contracts. In these instances the issuer may elect to apply either IAS 39 or IFRS 4. Under the amended IAS 39, a financial guarantee contract is initially recognized at fair value and is subsequently measured at the higher of (a) the amount determined in accordance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets and (b) the amount initially recognized, less, when appropriate, cumulative amortization recognized in accordance with IAS 18 Revenue . The amendment to IAS 39 is effective for accounting periods beginning on or after 1 January 2006. This standard impacts guarantees given by Group companies in respect of associates and joint ventures as well as in respect of other third parties; these will need to be recorded in the Group s financial statements at fair value.

Several interpretations have been issued by the International Financial Reporting Interpretations Committee (IFRIC) that will become effective for future financial reporting periods.

IFRIC 5 Rights to Interests Arising from Decommissioning, Restoration and Environmental Rehabilitation Funds sets out the accounting and disclosures required with regard to decommissioning funds. This interpretation is effective for annual accounting periods beginning on or after January 1, 2006 and has been adopted by the European Union (EU).

IFRIC 6 Liabilities Arising from Participating in a Specific Market Waste Electrical and Electronic Equipment provides guidance on the recognition of liabilities for waste management under the EU Directive on waste electrical and electronic equipment in respect of sales of household equipment before a certain date. This interpretation is effective for annual accounting periods beginning on or after December 1, 2005 and has been adopted by the EU.

IFRIC 7 Applying IAS 29 for the First Time provides detailed guidance on the application of IAS 29 Financial Reporting in Hyperinflationary Economies in the accounting period in which hyperinflation is first observed. This interpretation is effective for annual accounting periods beginning on or after March 1, 2006 and was adopted by the EU in May 2006.

IFRIC 8 Scope of IFRS 2 clarifies that IFRS 2 Share-based Payment is applicable to arrangements where an entity makes share-based payments for nil consideration, or where the consideration is less than the fair value of the options granted. This interpretation is effective for annual accounting periods beginning on or after May 1, 2006 and has yet to be adopted by the EU. This is expected in summer 2006.

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

IFRIC 9 Reassessment of Embedded Derivatives clarifies that an entity is required to assess whether an embedded derivative should be separated from the host contract and accounted for as a derivative when the entity first becomes a party to the contract. Subsequent reassessment is prohibited unless there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required under the contract, in which case reassessment is required. This interpretation is effective for annual accounting periods beginning on or after June 1, 2006 and has yet to be adopted by the EU. This is expected in summer 2006.

It is not anticipated that any of these interpretations will materially affect the Group s reported income or net assets.

Note 2 Resegmentation

With effect from January 1, 2005, there have been the following changes to the business segments reported by the Group:

(a) The Mardi Gras pipeline system in the Gulf of Mexico has been transferred from Exploration and Production to Refining and Marketing.
(b) The aromatics and acetyls operations and the petrochemicals assets that are integrated with our Gelsenkirchen refinery in Germany have been transferred from the former Petrochemicals segment to Refining and Marketing.
(c) The olefins and derivatives operations have been transferred from the former Petrochemicals segment to the Olefins and Derivatives business. The legacy historical results of other petrochemicals assets that had been divested during 2004 and 2003 are included within Other businesses and corporate.
(d) The Grangemouth and Lavéra refineries have been transferred from Refining and Marketing to the Olefins and Derivatives business to maintain existing operating synergies with the co-located olefins and derivatives operations.
(e) A small US operation, the Hobbs fractionator, which supplies petrochemicals feedstock, has been transferred from Gas, Power and Renewables to the Olefins and Derivatives business.

The Olefins and Derivatives business is reported within Other businesses and corporate. This reorganization was a precursor to seeking to divest the Olefins and Derivatives business. As indicated in Note 5, Discontinued operations, during 2005 we divested Innovene and show its activities as discontinued operations in these accounts. Innovene represented the majority of the Olefins and Derivatives business.

Comparative financial and operating information is shown after resegmentation and the adoption of International Financial Reporting Standards.

Note 3 Sales and other operating revenues

BP uses commodity derivative financial instruments to manage its exposure to market price risk associated with oil, natural gas NGLs and power and for trading purposes. These contracts include exchange traded commodity derivatives, such as futures and options traded on a recognized Exchange, over-the-counter swaps, forwards and options. Apart from over-the-counter forward contracts, all realized and unrealized gains and losses on these contracts are included in sales and other operating revenues.

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 3 Sales and other operating revenues (continued)

The Group s accounting policy has been to present oil, natural gas, NGL and power over-the-counter forward sale and purchase contracts gross in the income statement. Unrealized gains and losses are included in sales and other operating revenues.

During 2005, a review was undertaken into the presentation of over-the-counter forward contracts and related activity in the context of the final transition to IFRS for the Group s 2005 year end financial reporting. This review concluded that revenues associated with over-the-counter forward contracts where market mechanisms, similar to exchange traded instruments, have developed for financial net settlement and where frequent buying and selling patterns are present which are not part of the Group s risk management activities, but are indicative of the intent to generate profits from short term differences in prices, should be presented net.

The impact of this change is to reduce sales and other operating revenues and purchases, but has no effect on reported profit, cash flows and the balance sheet.

This change was originally reported in the UK Annual Report and Accounts for the year ended December 31, 2005. Subsequently the Group identified certain further adjustments to Sales and other operating revenues and Purchases. These further adjustments have been reflected in the consolidated statement of income for each of the three years in the period ending December 31, 2005 included herein. The following table sets out the impact on these line items for all periods presented as originally reported and as restated for the subsequent further adjustments. The information presented below includes the impact of the Innovene operations for all periods presented:

	Year ended December 31,		
	2005	2004	2003
		($ million)	
Sales and other operating revenues			
As originally reported	261,841	211,155	178,403
As restated	252,168	203,303	173,615
Purchases			
As originally reported	180,786	143,837	122,055
As restated	171,113	135,985	117,267

This change is a transition adjustment from UK GAAP to IFRS and should be read in conjunction with Note 52 First-time adoption of International Financial Reporting Standards.

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 3 Sales and other operating revenues (continued)

Sales and other operating revenues

Year ended December 31, 2004

	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total Group	Innovene operations	Consolidation adjustment and eliminations	Total continuing operations
	($ million)								
By business as reported in Form 20-F for 2004									
Segment revenues	34,700	192,917	83,320	17,994	(43,999)	284,932	(17,448)	6,169	273,653
Less: sales between businesses	(24,756)	(10,632)	(2,442)	(6,169)	43,999		6,169	(6,169)	
Third party sales	9,944	182,285	80,878	11,825		284,932	(11,279)		273,653
By business as restated									
Segment revenues	34,700	170,749	23,859	17,994	(43,999)	203,303	(17,448)	6,169	192,024
Less: sales between businesses	(24,756)	(10,632)	(2,442)	(6,169)	43,999		6,169	(6,169)	
Third party sales	9,944	160,117	21,417	11,825		203,303	(11,279)		192,024

Year ended December 31, 2003

	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total Group	Innovene operations	Consolidation adjustment and eliminations	Total continuing operations

($ million)

By business as reported in Form 20-F for 2004									
Segment revenues	30,621	159,263	65,639	13,978	(36,993)	232,508	(13,463)	4,501	223,546
Less: sales between businesses	(22,885)	(7,644)	(1,963)	(4,501)	36,993		4,501	(4,501)	
Third party sales	7,736	151,619	63,676	9,477		232,508	(8,962)		223,546
By business as restated									
Segment revenues	30,621	143,441	22,568	13,978	(36,993)	173,615	(13,463)	4,501	164,653
Less: sales between businesses	(22,885)	(7,644)	(1,963)	(4,501)	36,993		4,501	(4,501)	
Third party sales	7,736	135,797	20,605	9,477		173,615	(8,962)		164,653

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 3 Sales and other operating revenues (continued)

	Year ended December 31, 2004				
	UK	Rest of Europe	USA	Rest of World	Total
			($ million)		
By geographical area as reported in Form 20-F for 2004					
Segment revenues	81,155	54,570	130,652	67,777	334,154
Less: sales attributable to Innovene operations	(6,067)	(9,712)	(4,060)	(467)	(20,306)
Segment revenues from continuing operations	75,088	44,858	126,592	67,310	313,848
Less: sales between areas	(18,846)	(1,396)	(1,539)	(10,188)	(31,969)
Less: sales by continuing operations to Innovene	(5,263)	(896)	(2,064)	(3)	(8,226)
Third party sales of continuing operations	50,979	42,566	122,989	57,119	273,653
By geographical area as restated					
Segment revenues	59,615	52,540	86,358	48,534	247,047
Less: sales attributable to Innovene operations	(2,365)	(7,682)	(4,109)	(672)	(14,828)
Segment revenues from continuing operations	57,250	44,858	82,249	47,862	232,219
Less: sales between areas	(18,846)	(1,396)	(1,539)	(10,188)	(31,969)
Less: sales by continuing operations to Innovene	(5,263)	(896)	(2,064)	(3)	(8,226)
Third party sales of continuing operations	33,141	42,566	78,646	37,671	192,024

	Year ended December 31, 2003				
	UK	Rest of Europe	USA	Rest of World	Total
			($ million)		
By geographical area as reported in Form 20-F for 2004					
Segment revenues	54,971	50,703	108,910	52,314	266,898
Less: sales attributable to Innovene operations	(5,719)	(8,670)	(3,226)	(374)	(17,989)
Segment revenues from continuing operations	49,252	42,033	105,684	51,940	248,909
Less: sales between areas	(6,953)	(3,160)	(714)	(8,258)	(19,085)
Less: sales by continuing operations to Innovene	(3,947)	(876)	(1,455)		(6,278)
Third party sales of continuing operations	38,352	37,997	103,515	43,682	223,546

By geographical area as restated

Segment revenues	36,253	48,138	79,092	38,316	201,799
Less: sales attributable to Innovene operations	(1,879)	(6,105)	(3,265)	(534)	(11,783)
Segment revenues from continuing operations	34,374	42,033	75,827	37,782	190,016
Less: sales between areas	(6,953)	(3,160)	(714)	(8,258)	(19,085)
Less: sales by continuing operations to Innovene	(3,947)	(876)	(1,455)		(6,278)
Third party sales of continuing operations	23,474	37,997	73,658	29,524	164,653

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 3 Sales and other operating revenues (concluded)

Purchases

	Year ended December 31, 2004		Year ended December 31, 2003	
	Total Group	Continuing operations	Total Group	Continuing operations
	($ million)			
As reported in Form 20-F for 2004	217,614	209,684	176,160	170,083
As restated	135,985	128,055	117,267	111,190

Note 4 Acquisitions

Acquisitions in 2005

BP made a number of minor acquisitions in 2005 for a total consideration of $84 million. All these business combinations were accounted for using the acquisition method of accounting. No significant fair value adjustments were made to the acquired assets and liabilities. Goodwill of $27 million arose on these acquisitions. There was also additional goodwill on the Solvay acquisition of $59 million (see below).

Acquisitions in 2004

	Year ended December 31, 2004		
	Book value on acquisitions	Fair value adjustments	Fair value
	($ million)		
Property, plant and equipment	703	760	1,463
Intangible assets	15		15
Current assets (excluding cash)	721		721
Cash and cash equivalents	36		36
Trade and other payables	(329)		(329)
Deferred tax liabilities		(185)	(185)
Defined benefit pension plan deficits	(3)		(3)
Net investment in equity-accounted entities transferred to full consolidation	(547)	(94)	(641)
Net assets acquired	596	481	1,077
Goodwill			328
Consideration			1,405

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, subject to final closing adjustments. There were closing adjustments and selling costs in 2005 amounting to $59 million. These created additional goodwill of $59 million, which was written off. See Note 14 Impairment of goodwill, for further

BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 4 Acquisitions (continued)

information. Other minor acquisitions were made for a total consideration of $14 million. All business combinations have been accounted for using the acquisition method of accounting. The fair value of the property, plant and equipment has been estimated by determining the net present value of future cash flows. No significant adjustments were made to the other assets and liabilities acquired. The assets and liabilities acquired as part of the 2004 acquisitions are shown in aggregate in the table above.

Acquisitions in 2003

BP made a number of minor acquisitions in 2003 for a total consideration of $232 million. All these business combinations were accounted for using the acquisition method of accounting. No significant fair value adjustments were made to the acquired assets and liabilities. Goodwill of $5 million arose on these acquisitions.

Note 5 Discontinued operations

BP announced on October 7, 2005 its intention to sell Innovene, its olefins, derivatives and refining group, to INEOS. The transaction became unconditional on December 9, 2005 on receipt of European Commission clearance and was completed on December 16, 2005. The transaction included all Innovene s manufacturing sites, markets and technologies. The equity-accounted investments in China and Malaysia that were part of the Olefins and Derivatives business remain with BP and are included within Other businesses and corporate.

The Innovene operations represented a separate major line of business for BP. As a result of the sale, these operations have been treated as discontinued operations for the year ended December 31, 2005. A single amount is shown on the face of the income statement comprising the post-tax result of discontinued operations and the post-tax loss recognized on the remeasurement to fair value less costs to sell and on disposal of the discontinued operation. That is, the income and expenses of Innovene are reported separately from the continuing operations of the BP Group. The table below provides further detail of the amount shown on the income statement. The income statements for prior periods have been restated to conform to this style of presentation.

In the cash flow statement, the cash provided by the operating activities of Innovene has been separated from that of the rest of the Group and reported as a single line item.

Gross proceeds received amounted to $8,477 million. There were selling costs of $120 million and initial closing adjustments of $43 million. The proceeds are subject to final closing adjustments. The remeasurement to fair value less costs to sell resulted in a loss of $591 million before tax. The originally announced transaction value of $9,000 million has been reduced by the value of certain liabilities transferred to INEOS and certain assets retained by BP on closing.

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 5 Discontinued operations (concluded)

Financial information for the Innovene operations after Group eliminations is presented below.

	Years ended December 31,		
	2005	**2004**	**2003**
		($ million)	
Total revenues and other income	12,441	11,327	8,986
Expenses	11,709	12,041	9,034
Profit (loss) before interest and taxation	732	(714)	(48)
Other finance income (expense)	3	(17)	(15)
Profit (loss) before taxation and loss recognized on remeasurement to fair value less costs to sell and on disposal	735	(731)	(63)
Loss recognized on remeasurement to fair value less costs to sell and on disposal	(591)		
Profit (loss) before taxation from Innovene operations	144	(731)	(63)
Tax (charge) credit			
On profit (loss) before loss recognized on remeasurement to fair value less costs to sell and on disposal	(306)	109	
On loss recognized on remeasurement to fair value less costs to sell and on disposal	346		
Profit (loss) from Innovene operations	184	(622)	(63)
Earnings (loss) per share from Innovene operations cents			
Basic	0.87	(2.85)	(0.28)
Diluted	0.86	(2.79)	(0.28)
The cash flows of Innovene operations are presented below			
Net cash provided by (used in) operating activities	970	(669)	348
Net cash used in investing activities	(524)	(1,731)	(572)
Net cash provided by (used in) financing activities	(446)	2,400	224

Further information is contained in Note 6 Disposals.

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 6 Disposals

	Years ended December 31,		
	2005	2004	2003
		($ million)	
Proceeds from the sale of Innovene operations	8,304		
Proceeds from the sale of other businesses	93	725	179
Proceeds from the sale of businesses	8,397	725	179
Proceeds from the sale of property, plant and equipment	2,803	4,236	6,177
	11,200	4,961	6,356
Exploration and Production	1,416	914	4,801
Refining and Marketing	888	1,007	1,050
Gas, Power and Renewables	540	144	67
Other businesses and corporate	8,356	2,896	438
	11,200	4,961	6,356

As part of the strategy to upgrade the quality of its asset portfolio, the Group has an active programme to dispose of non-strategic assets. In the normal course of business in any particular year, the Group may sell interests in exploration and production properties, service stations and pipeline interests as well as non-core businesses.

Cash received during the year from disposals amounted to $11.2 billion (2004 $5.0 billion and 2003 $6.4 billion). The divestment of Innovene contributed $8.3 billion to this total. The major transactions in 2004 that generated over $2.3 billion of proceeds were the sale of the Group s investments in PetroChina and Sinopec.

For 2003, the major disposals representing over $3.0 billion of the proceeds were the divestment of a further 20% interest in BP Trinidad and Tobago LLC, the sale of 50% of our interest in the In Amenas gas condensate project and 49% of our interest in the In Salah gas development in Algeria, and the sale of the UK North Sea Forties oil field, together with a package of 61 shallow-water assets in the Gulf of Mexico. The principal transactions generating the proceeds for each segment are described below.

Exploration and Production. The Group divested interests in a number of oil and natural gas properties in all three years. During 2005, the major transaction was the sale of the Group s interest in the Ormen Lange field in Norway. In addition, the Group sold interests in oil and natural gas properties in Venezuela, Canada and the Gulf of Mexico. In 2004, in the US we sold 45% of our interest in King s Peak in the deepwater Gulf of Mexico to Marubeni Oil & Gas, divested our interest in Swordfish, and additionally, we sold various properties including our interest in the South Pass 60 property in the Gulf of Mexico Shelf. In Canada, BP sold various assets in Alberta to Fairborne Energy. In Indonesia, we disposed of our interest in the Kangean Production Sharing Contract and our participating interest in the Muriah Production Sharing Contract. In 2003, the UK North Sea Forties oil field, together with a package of 61 shallow-water assets in the Gulf of Mexico, were sold to Apache. A 12.5% interest in the Tangguh liquefied natural gas project in Indonesia was sold to CNOOC. Interests in 14 UK Southern North Sea gas fields, together with associated pipelines and onshore processing facilities, including the Bacton terminal, were sold to Perenco. BP sold 50% of its interest in the In Amenas gas condensate project and 49% of its interest in the In Salah gas development in Algeria to Statoil. In January 2003,

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 6 Disposals (continued)

Repsol exercised its option to acquire a further 20% interest in BP Trinidad and Tobago LLC. BP s interest in the company is now 70%. In February 2003, BP called its $420 million Exchangeable Bonds which were exchangeable for Lukoil American Depositary Shares (ADSs). Bondholders converted to ADSs before the redemption date.

Refining and Marketing. The churn of retail assets represents a significant element of the total in all three years. During 2005, the Group sold a number of regional retail networks in the US and in addition its retail network in Malaysia. During 2004, major asset transactions included the sale of the Singapore refinery, the divestment of the European speciality intermediate chemicals business, and the Cushing and other pipeline interests in the US. As a condition of the approval of the acquisition of Veba in 2002, BP was, amongst other things, required to divest approximately 4% of its retail market share in Germany and a significant portion of its Bayernoil refining interests. The sale of 494 retail sites in the northern and northeastern part of Germany to PKN Orlen and the sale of retail and refinery assets in Germany and Central Europe to OMV in 2003 completed the divestments required.

Gas, Power and Renewables. In 2005, the Group sold its interest in the Interconnector pipeline. During 2004, the Group sold its interest in two Canadian natural gas liquids plants.

Other businesses and corporate. 2005 includes the proceeds from the sale of Innovene. The disposal of the Group s investments in PetroChina and Sinopec were the major transactions in 2004. In addition, the Group sold its US speciality intermediate chemicals and fabrics and fibres businesses. In 2003, the Group sold its 50% interest in Kaltim Prima Coal, an Indonesian company, and completed the divestment of the former Burmah Castrol speciality chemicals business Sericol and Fosroc Mining.

Summarized financial information for the sale of businesses is shown below.

	Years ended December 31,		
	2005	2004	2003
	($ million)		
The disposals comprise the following			
Noncurrent assets	6,452	1,046	104
Other current assets	4,779	477	111
Noncurrent liabilities	(364)	(44)	(7)
Other current liabilities	(2,488)	(59)	(1)
	8,379	1,420	207
Profit (loss) on sale of businesses	18	(695)	(28)
Total consideration and net cash inflow	8,397	725	179

Subsequent transactions

On April 19, 2006, BP announced the sale of its producing properties on the Outer Continental Shelf of the Gulf of Mexico to Apache Corporation for $1.3 billion. The properties are in waters less than 1,200 feet deep and include 18 producing fields (11 which are operated) covering 92 blocks with estimated reserves of 59 million barrels of oil equivalent and average daily production of 27 mboe. Completion of the sale is expected in mid-2006 once regulatory approvals have been received. The assets held for sale at the date of the announcement amounted to $1,160 million and liabilities directly associated with the assets held for sale amounted to $399 million. The gain to be realized on the sale, to be reported in 2006, is expected to be $0.5 billion.

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 6 Disposals (concluded)

On June 27, 2006 BP announced its intention to sell its refinery at Coryton, UK. The assets held for sale at the date of the announcement amounted to approximately $1,200 million and liabilities directly associated with the assets held for sale amounted to approximately $600 million.

Note 7 Segmental analysis

The Group s primary format for segment reporting is business segments and the secondary format is geographical segments. The risks and returns of the Group s operations are primarily determined by the nature of the different activities that the Group engages in, rather than the geographical location of these operations. This is reflected by the Group s organizational structure and the Group s internal financial reporting systems.

BP has three reportable operating segments: Exploration and Production; Refining and Marketing; and Gas, Power and Renewables. Exploration and Production s activities include oil and natural gas exploration and field development and production, together with pipeline transportation and natural gas processing. The activities of Refining and Marketing include oil supply and trading as well as refining and petrochemicals manufacturing and marketing. Gas, Power and Renewables activities include marketing and trading of natural gas, natural gas liquids, new market development, liquefied natural gas (LNG) and solar and renewables. The Group is managed on an integrated basis.

Other businesses and corporate comprises Finance, the Group s aluminum asset, interest income and costs relating to corporate activities and also the portion of O&D not included in the sale of Innovene to INEOS.

The accounting policies of operating segments are the same as those described in Note 1 Significant accounting policies.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenue, segment expense and segment result include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation.

The Group s geographical segments are based on the location of the Group s assets. The UK and US are significant countries of activity for the Group; the other geographical segments are determined by geographical location.

Sales to external customers are based on the location of the seller, which in most circumstances is not materially different from the location of the customer. Crude oil and LNG are commodities for which there is an international market and buyers and sellers can be widely separated geographically. The UK segment includes the UK-based international activities of Refining and Marketing.

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 7 Segmental analysis (continued)

By business	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total Group	Innovene operations	Consolidation adjustment and eliminations[(a)]	Total continuing operations
					($ million)				
Year ended December 31, 2005									
Sales and other operating revenues									
Segment revenues	47,210	213,465	25,557	21,295	(55,359)	252,168	(20,627)	8,251	239,792
Less: sales between businesses	(32,606)	(11,407)	(3,095)	(8,251)	55,359		8,251	(8,251)	
Third party sales	14,604	202,058	22,462	13,044		252,168	(12,376)		239,792
Results									
Profit (loss) before interest and tax	25,508	6,442	1,104	(523)	(208)	32,323	(668)	527	32,182
Finance costs and other finance expense					(758)	(758)	(3)		(761)
Profit (loss) before taxation	25,508	6,442	1,104	(523)	(966)	31,565	(671)	527	31,421
Taxation					(9,248)	(9,248)	133	(173)	(9,288)
Profit (loss) for the year	25,508	6,442	1,104	(523)	(10,214)	22,317	(538)	354	22,133
Includes									
Equity-accounted income	3,238	238	19	34		3,529	14		3,543
Assets and liabilities as at December 31, 2005									
Segment assets	93,479	77,352	28,441	12,756	(5,326)	206,702			
Tax receivable					212	212			

Total assets	93,479	77,352	28,441	12,756	(5,114)	206,914		
Includes								
Equity-accounted investments	14,657	4,012	483	621		19,773		
Segment liabilities	(20,387)	32,227	(23,346)	(15,358)	4,548	(86,770)		
Current tax payable					(4,274)	(4,274)		
Finance debt					(19,162)	(19,162)		
Deferred tax liabilities					(16,258)	(16,258)		
Total liabilities	(20,387)	(32,227)	(23,346)	(15,358)	(35,146)	(126,464)		
Year ended December 31, 2005								
Other segment information								
Capital expenditure								
Intangible assets	989	451	31	10		1,481		
Property, plant and equipment	8,751	2,036	199	779		11,765		
Other	497	285	5	116		903		
Total	10,237	2,772	235	905		14,149		
Depreciation, depletion and amortization	6,033	2,392	225	533		9,183	(412)	8,771
Impairment	266	93		59		418	(59)	359
Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations				591		591	(591)	
Losses on sale of businesses and fixed assets	39	64		6		109		109
Gains on sale of businesses and fixed assets	1,198	241	55	47		1,541	(3)	1,538

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 7 Segmental analysis (continued)

By business	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total Group	Innovene operations	Consolidation adjustment and eliminations[a]	Total continuing operations
					($ million)				
Year ended December 31, 2004									
Sales and other operating revenues									
Segment revenues	34,700	170,749	23,859	17,994	(43,999)	203,303	(17,448)	6,169	192,024
Less: sales between businesses	(24,756)	(10,632)	(2,442)	(6,169)	43,999		6,169	(6,169)	
Third party sales	9,944	160,117	21,417	11,825		203,303	(11,279)		192,024
Results									
Profit (loss) before interest and tax	18,087	6,544	954	(362)	(191)	25,032	526	188	25,746
Finance costs and other finance expense					(797)	(797)	17		(780)
Profit (loss) before taxation	18,087	6,544	954	(362)	(988)	24,235	543	188	24,966
Taxation					(6,973)	(6,973)	(53)	(56)	(7,082)
Profit (loss) for the year	18,087	6,544	954	(362)	(7,961)	17,262	490	132	17,884
Includes									
Equity-accounted income	1,985	259	6	18		2,268	12		2,280
Assets and liabilities as at December 31, 2004									
Segment assets	85,808	73,581	17,257	22,292	(4,467)	194,471			
Tax receivable					159	159			

Total assets	85,808	73,581	17,257	22,292	(4,308)	194,630		
Includes								
Equity-accounted investments	14,327	4,486	573	656		20,042		
Segment liabilities	(16,214)	(28,903)	(12,384)	(18,886)	3,915	(72,472)		
Current tax payable					(4,131)	(4,131)		
Finance debt					(23,091)	(23,091)		
Deferred tax liabilities					(16,701)	(16,701)		
Total liabilities	(16,214)	(28,903)	(12,384)	(18,886)	(40,008)	(116,395)		
Year ended December 31, 2004								
Other segment information								
Capital expenditure								
Intangible assets	406	670	25	5		1,106		
Property, plant and equipment	8,696	1,960	328	690		11,674		
Other	1,906	189	171	1,605		3,871		
Total	11,008	2,819	524	2,300		16,651		
Depreciation, depletion and amortization	5,583	2,540	210	679		9,012	(483)	8,529
Impairment	404	195		891		1,490	(879)	611
Losses on sale of businesses and fixed assets	227	371		416		1,014	(235)	779
Gains on sale of businesses and fixed assets	162	104	56	1,365		1,687	(2)	1,685

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BP p.l.c. AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS (Continued)

Note 7 Segmental analysis (continued)

By business	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total Group	Innovene operations	Consolidation adjustment and eliminations[a]	Total continuing operations
					($ million)				
Year ended December 31, 2003									
Sales and other operating revenues									
Segment revenues	30,621	143,441	22,568	13,978	(36,993)	173,615	(13,463)	4,501	164,653
Less: sales between businesses	(22,885)	(7,644)	(1,963)	(4,501)	36,993		4,501	(4,501)	
Third party sales	7,736	135,797	20,605	9,477		173,615	(8,962)		164,653
Results									
Profit (loss) before interest and tax	15,084	3,235	578	(108)	(61)	18,728	(145)	193	18,776
Finance costs and other finance expense					(1,060)	(1,060)	15		(1,045)
Profit (loss) before	15,084	3,235	578	(108)	(1,121)	17,668	(130)	193	17,731

taxation									
Taxation					(5,050)	(5,050)	54	(54)	(5,050)
Profit (loss) for the year	15,084	3,235	578	(108)	(6,171)	12,618	(76)	139	12,681

Includes