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.

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.

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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

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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.

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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	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
	Year ended December 31, 2003								
	($ 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	UK	Rest of Europe	USA	Rest of World	Total
	Year ended December 31, 2005				
	($ 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 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.

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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			Year ended December 31,		
			Net production		
Production	**Field or Area**	**Interest**	**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			