BP PLC
Form 20-F
June 30, 2006

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 20-F

(Mark One)

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

Table of Contents

TABLE OF CONTENTS

Table of Contents

CERTAIN DEFINITIONS

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

Oil and natural gas reserves

Proved oil and gas reserves Proved reserves are defined by the 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.

Table of Contents

Miscellaneous terms

ADR American Depositary Receipt.
ADS American Depositary Share.
Amoco The former Amoco Corporation and its subsidiaries.
Atlantic Richfield Atlantic Richfield Company and its subsidiaries.
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.

Table of Contents

PART I

ITEM 1 IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

Not applicable.

ITEM 2 OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

ITEM 3 KEY INFORMATION

SELECTED FINANCIAL INFORMATION

Summary

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

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.

7

Table of Contents

	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.

Table of Contents

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.

Table of Contents

RISK FACTORS

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

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.

Table of Contents

FORWARD LOOKING STATEMENTS

In order to utilize the Safe Harbor provisions of the United States Private Securities Litigation Reform Act of 1995, BP is providing the following cautionary statement. This document contains certain forward looking statements with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , should , may , is likely to , intends , believes , 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.

Table of Contents

ITEM 4 INFORMATION ON THE COMPANY

GENERAL

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

Table of Contents

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

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.

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

19

Table of Contents

Year ended December 31, 2003

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	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.

Year ended December 31, 2005

By geographical area	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

20

Table of Contents

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

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

22

Table of Contents

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).

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

Table of Contents

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.

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)

Table of Contents

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.

Table of Contents

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.

29

Table of Contents

Production	Field or Area	Interest	2005	2004	2003
			Year ended December 31,		
			Net production		
		(%)	(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.

Table of Contents

Natural gas

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

Table of Contents

Production	Field or Area	Interest	2005	2004	2003
			Year ended December 31,		
			Net production		
		(%)	(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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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%

Table of Contents

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.

Table of Contents

REFINING AND MARKETING

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

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.

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.

Table of Contents

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.

Table of Contents

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 barrels 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.

Table of Contents

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.

Table of Contents

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.

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.

Table of Contents

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.

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.

Table of Contents

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.

Table of Contents

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 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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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%).

Table of Contents

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.

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.

Table of Contents

ENVIRONMENTAL PROTECTION

Health, Safety and Environmental Regulation

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

The extent and cost of future environmental restoration, remediation and abatement programmes are often inherently difficult to estimate. They depend on the magnitude of any possible contamination, the timing and extent of the corrective actions required, 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 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

Table of Contents

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.

Table of Contents

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 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

Table of Contents

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.

Table of Contents

PROPERTY, PLANTS AND EQUIPMENT

BP has freehold and leasehold interests in real estate in numerous countries throughout the world, but no one individual property is significant to the Group as a whole. See Exploration and Production 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.

Table of Contents

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

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

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.

Table of Contents

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.

Table of Contents

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, comp