

BP PLC
Form 20-F
March 06, 2007

**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
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended 31 December 2006

**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)

Title of each class
Ordinary Shares of 25c each

Name of each exchange on which registered
**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

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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	19,510,496,490
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 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

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 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	Accelerated filer	Non-accelerated filer
Indicate by check mark which financial statement item the registrant has elected to follow.		

Item 17 Item 18

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

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Certain definitions

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

Oil and natural gas reserves

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

- (i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test.
The area of a reservoir considered proved includes: (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.
- (ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed programme in the reservoir, provides support for the engineering analysis on which the project or programme was based.
- (iii) Estimates of proved reserves do not include the following:
 - (a) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves";
 - (b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
 - (c) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and
 - (d) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

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

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

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Miscellaneous terms

ADR American depositary receipt.

ADS American depositary share.

Amoco The former Amoco Corporation and its subsidiaries.

Atlantic Richfield Atlantic Richfield Company and its subsidiaries.

Associate An entity over which the group has significant influence and that is neither a subsidiary nor a joint venture. Significant influence is the power to participate in the financial and operating policy decisions of an entity without having control or joint control over those policies.

Barrel 42 US gallons.

b/d Barrels per day.

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.

Joint venture A contractual arrangement between the group and other venturers that undertake an economic activity that is subject to joint control. Joint control exists only where the strategic financial and operating decisions relating to the activity require the unanimous consent of the venturers.

Jointly controlled asset A joint venture where the venturers have a direct ownership interest in and jointly control the assets of the venture.

Jointly controlled entity A joint venture that involves the establishment of a company, partnership or other entity to engage in economic activity that the group jointly controls with fellow venturers.

Liquids Crude oil, condensate and natural gas liquids.

LNG Liquefied natural gas.

London Stock Exchange or LSE London Stock Exchange plc.

LPG Liquefied petroleum gas.

mb/d thousand barrels per day.

mboe/d thousand barrels of oil equivalent per day.

mmBtu million British thermal units.

mmcf/d million cubic feet per day.

MTBE Methyl tertiary butyl ether.

NGLs Natural gas liquids.

OPEC Organisation 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.

PSA Production-sharing agreement.

SEC The United States Securities and Exchange Commission.

Subsidiary An entity that is controlled by the BP group. Control is the power to govern the financial and operating policies of an entity so as to obtain the benefits from its activities.

Tonne 2,204.6 pounds.

UK United Kingdom of Great Britain and Northern Ireland.

UK GAAP Generally Accepted Accounting Practice in the UK.

US or USA United States of America.

US GAAP Generally Accepted Accounting Principles in the US.

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Performance review

Selected financial and operating information

This information, insofar as it relates to 2006, has been extracted or derived from the audited financial statements of the BP group presented on pages 85-193. The selected information should be read in conjunction with the audited financial statements and related Notes elsewhere herein.

The financial information for 2005 and 2004 has been restated to reflect the following, all with effect from 1 January 2006: (a) the transfer of three equity-accounted entities from Other businesses and corporate to Refining and Marketing following the sale of Innovene; (b) the transfer of certain mid-stream assets and activities from Refining and Marketing and Exploration and Production to Gas, Power and Renewables; and (c) the transfer of Hydrogen for Transport activities from Gas, Power and Renewables to Refining and Marketing. (See *Financial statements* □ *Note 2 on page 101 for further details.*)

BP sold its Innovene operations in December 2005. 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 its refineries was supplied by BP and most of the refined products manufactured by Innovene were 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. This representation does not indicate the profits earned by continuing or Innovene operations, as if they were standalone entities, for past periods or those likely to be earned in future periods. Under US GAAP, Innovene operations would not be classified as discontinued operations due to BP's continuing customer/supplier arrangements with Innovene. For a full description of the differences between IFRS and US GAAP, see Financial statements □ *Note 53 on page 169.*

IFRS

\$ million except per share amounts

	2006	2005	2004	2003
Income statement data				
Sales and other operating revenues from continuing operations ^a	265,906	239,792	192,024	164,653
Profit before interest and taxation from continuing operations ^a	35,658	32,182	25,746	18,776
Profit from continuing operations ^a	22,626	22,133	17,884	12,681
Profit for the year	22,601	22,317	17,262	12,618
Profit for the year attributable to BP shareholders	22,315	22,026	17,075	12,448
Capital expenditure and acquisitions ^b	17,231	14,149	16,651	19,623
Per ordinary share □ cents				
Profit for the year attributable to BP shareholders				
Basic	111.41	104.25	78.24	56.14
Diluted	110.56	103.05	76.87	55.61
Profit from continuing operations attributable to BP shareholders				
Basic	111.54	103.38	81.09	56.42
Diluted	110.68	102.19	79.66	55.89
Dividends per share □ cents	38.40	34.85	27.70	25.50

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Dividends per share  pence	21.104	19.152	15.251	15.658
Ordinary share data^C				
Average number outstanding of 25 cent ordinary shares (shares million undiluted)	20,028	21,126	21,821	22,171
Average number outstanding of 25 cent ordinary shares (shares million diluted)	20,195	21,411	22,293	22,424
Balance sheet data				
Total assets	217,601	206,914	194,630	172,491
Net assets	85,465	80,450	78,235	70,264
Share capital	5,385	5,185	5,403	5,552
BP shareholders' equity	84,624	79,661	76,892	69,139
Finance debt due after more than one year	11,086	10,230	12,907	12,869
Net debt to net debt plus equity	20%	17%	22	22%

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

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\$ million except per share amounts

	2006	2005	2004	2003	2002
Income statement data					
Revenues ^d	265,906	252,168	203,303	173,615	145,991
Profit for the year attributable to BP shareholders ^d	21,116	19,642	17,090	12,941	8,109
Comprehensive income	23,125	17,053	17,371	19,689	10,256
Profit per ordinary share □ cents					
Basic	105.42	92.96	78.31	58.36	36.20
Diluted	104.63	91.91	76.88	57.79	36.02
Profit per American depositary share □ cents					
Basic	632.52	557.76	469.86	350.16	217.20
Diluted	627.78	551.46	461.28	346.74	216.12
Balance sheet data					
Total assets	219,288	213,722	206,139	186,576	164,103
Net assets	87,358	85,936	86,435	80,292	67,274
BP shareholders □ equity	86,517	85,147	85,092	79,167	66,636

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 *Financial statements* □ *Note 5 on page 103*). Under US GAAP, Innovene is not treated as a discontinued operation.

b There were no significant acquisitions in 2006 or in 2005. Capital expenditure in 2006 includes \$1 billion in respect of our investment in Rosneft. 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. With the exception of the shares issued to Alfa Group and Access-Renova (AAR) in connection with TNK-BP (2004-2006), all capital expenditure and acquisitions during the last five years have been financed from cash flow from operations, disposal proceeds and external financing.

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

d Under US GAAP, Innovene is not treated as a discontinued operation. (See *Financial statements* □ *Note 5 on page 103*). As such, the results of Innovene are included within revenues and profit for the year, as adjusted to accord with US GAAP.

Production and net proved oil and natural gas reserves

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.

	2006	2005	2004	2003	2002
Crude oil production for subsidiaries (thousand barrels per day)	1,351	1,423	1,480	1,615	1,766
Crude oil production for equity-accounted entities (thousand barrels per day)	1,124	1,139	1,051	506	252
Natural gas production for subsidiaries (million cubic feet per day)	7,412	7,512	7,624	8,092	8,324
Natural gas production for equity-accounted entities (million cubic feet per day)	1,005	912	879	521	383
Estimated net proved crude oil reserves for subsidiaries (million barrels)a b	5,893	6,360	6,755	7,214	7,762
Estimated net proved crude oil reserves for equity-accounted entities (million barrels)a c	3,888	3,205	3,179	2,867	1,403
Estimated net proved natural gas reserves for subsidiaries (billion cubic feet)a d	42,168	44,448	45,650	45,155	45,844
Estimated net proved natural gas reserves for equity-accounted entities (billion cubic feet)a e	3,763	3,856	2,857	2,869	2,945

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.

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- b Includes 23 million barrels (29 million barrels at 31 December 2005 and 40 million barrels at 31 December 2004) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
- c Includes 179 million barrels (95 million barrels at 31 December 2005 and 127 million barrels at 31 December 2004) in respect of the 6.29% minority interest in TNK-BP (4.47% at 31 December 2005 and 5.9% at 31 December 2004).
- d Includes 3,537 billion cubic feet of natural gas (3,812 billion cubic feet at 31 December 2005 and 4,064 billion cubic feet at 31 December 2004) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
- e Includes 99 billion cubic feet (57 billion cubic feet at 31 December 2005 and 13 billion cubic feet at 31 December 2004) in respect of the 7.77% minority interest in TNK-BP (4.47% at 31 December 2005 and 5.9% at 31 December 2004).

During 2006, 329 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 963mmboe, BP's proved reserves for subsidiaries were 13,163mmboe at 31 December 2006. These proved reserves are mainly located in the US (44%), Rest of Americas (20%), Asia Pacific (10%), Africa (9%) and the UK (8%).

For equity-accounted entities, 1,306mmboe were added to proved reserves (excluding purchases and sales), production was 479mmboe and proved reserves were 4,537mmboe at 31 December 2006.

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

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Risk factors

We urge you to consider carefully the risks described below. If any of these risks 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 could lose all or part of your investment.

Our system of risk management provides the response to enduring risks of group significance through the establishment of standards and other controls. Inability to identify, assess and respond to risks through this and other controls could lead to inability to capture opportunities, threats materializing, inefficiency and legal non-compliance.

The risks are categorized against the following areas: Strategy, Compliance and ethics, Financial control and operations.

Strategic risks

Access and renewal

Successful execution of our group plan depends critically on implementing activities to renew and reposition our portfolio. The challenges to renewal of our upstream portfolio are growing due to increasing competition for access to opportunities globally. Inability to complete planned disposals and/or lack of material positions in new markets could result in an inability to capture above-average market growth.

Prices and markets

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.

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.

Socio-political

We have operations in developing countries where political, economic and social transition is taking place. Some countries have experienced political instability, changes to the regulatory environment, 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.

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. If it is perceived that we are not respecting or advancing the economic and social progress of the communities in which we operate, our reputation and shareholder value could be damaged.

Competition

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.

Compliance and ethics risks

Regulatory

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. We buy, sell and trade oil and gas products in certain regulated commodity markets. 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, or we could incur additional costs.

Ethical misconduct and non-compliance

Our code of conduct, which applies to all employees, defines our commitment to integrity, compliance with all applicable legal requirements, high ethical standards and the behaviours and actions we expect of our businesses and people wherever we operate. Incidents of non-compliance with applicable laws and regulation or ethical misconduct could be damaging to our reputation and shareholder value. Multiple events of non-compliance could call into question the integrity of our operations.

Financial control risks

Liquidity, financial capacity and financial exposure

The group has established a financial framework to ensure that it is able to maintain an appropriate level of liquidity and financial capacity and to constrain the level of assessed capital at risk for the purposes of positions taken in financial instruments. Failure to operate within our financial framework could lead to the group becoming financially distressed leading to a loss of shareholder value. Commercial credit risk is measured and controlled to determine the group's total credit risk. Inability adequately to determine our credit exposure could lead to financial loss. 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.

Liabilities and provisions

Changes in the external environment, such as new laws and regulations, market volatility or other factors, could affect the adequacy of our provisions for pensions, tax, environmental and legal liabilities.

Operations risks

Operations – safety and operations

Process safety

Inherent in our operations are hazards that require continual oversight and control. There are risks of technical integrity failure and loss of containment of hydrocarbons and other hazardous material at operating sites or pipelines. Failure to manage these risks could result in injury or loss of life, environmental damage and/or loss of production.

Personal safety

Inability to provide safe environments for our workforce and the public could lead to injuries or loss of life.

Environmental

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, we could fail to live up to our aspirations of no or minimal damage to the environment and contributing to human progress.

Product quality

Supplying customers with on-specification products is critical to maintaining our licence to operate and our reputation in the marketplace. Failure to meet product quality standards throughout the value chain could lead to harm to people and the environment and loss of customers.

Drilling and production

Exploration and production require high levels of investment and 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

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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.

Transportation

All modes of transportation of hydrocarbons contain inherent risks. A loss of containment of hydrocarbons and other hazardous material could occur during transportation by road, rail or sea. This is a significant risk due to the potential impact of a release on the environment and people and given the high volumes involved.

Operations □ planning and performance management

Investment efficiency

Our organic growth is dependent on creating a portfolio of quality options and investing in the best options. Ineffective investment selection could lead to loss of value and higher capital expenditure.

Major project delivery

Successful execution of our group plan depends critically on implementing the activities to deliver the major projects over the plan period. Poor delivery of any major project that underpins production growth and/or a major programme designed to enhance shareholder value could adversely affect our financial performance.

Reserves replacement

Successful execution of our group plan (see page 10) depends critically on sustaining long-term reserves replacement. If upstream resources are not progressed to proved reserves in a timely and efficient manner, we will be unable to sustain long-term replacement of reserves.

Operations □ enterprise systems, security and continuity

Digital infrastructure

The reliability and security of our digital infrastructure are critical to maintaining our business applications availability. A breach of our digital security could cause serious damage to business operations and, in some circumstances, could result in injury to people, damage to assets, harm to the environment and breaches of regulations.

Security

Security threats require continual oversight and control. Acts of terrorism that threaten our plants and offices, pipelines, transportation or computer systems would severely disrupt business and operations and could cause harm to people.

Business continuity and disaster recovery

Contingency plans are required to continue or recover operations following a disruption or incident. Inability to restore or replace critical capacity to an agreed level within an agreed timeframe would prolong the impact of any disruption and could severely affect business and operations.

Crisis management

Crisis management plans and capability are essential to deal with emergencies at every level of our operations. If we do not respond or are perceived not to respond in an appropriate manner to either an external or internal crisis, our business and operations could be severely disrupted.

Operations □ people management

People and capability

Employee training, development and successful recruitment of new staff are key to implementation of our plans. Inability to develop the human capacity and capability across the organization could jeopardize performance delivery.

Forward-looking statement

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", "objective", "is likely to", "intends", "believes", "plans", "we see" or similar expressions. In particular, among other statements, (i) certain statements in Performance review (pages 6-57) 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, the timing of divestments and impact of health, safety and environmental regulations; (ii) the statements in Performance review (pages 10-39) with regard to planned expansion, investment or other projects and future regulatory actions; (iii) the statements in Performance review (pages 40-57) 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 post-retirement 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; and (iv) 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, those set out 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 referring to BP's competitive position are based on the company's belief and in some cases rely on a range of sources, including investment analysts' reports, independent market studies and BP's internal assessments of market share based on publicly available information about the financial results and performance of market participants.

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Information on the company

General

Unless otherwise indicated, information in this document reflects 100% of the assets and operations of the company and its subsidiaries that 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.

The British Petroleum Company p.l.c., incorporated in 1909 in England and Wales, became known as BP Amoco p.l.c. following the merger with Amoco Corporation (incorporated in Indiana, US, in 1889). The company subsequently changed its name to BP p.l.c.

BP is one of the world's leading oil companies on the basis of market capitalization and proved reserves. Our worldwide headquarters is located at 1 St James's Square, London SW1Y 4PD, UK. Telephone +44 (0)20 7496 4000. Our agent in the US is BP America Inc., 4101 Winfield Road, Warrenville, Illinois 60555. Telephone +1 630 821 2222.

Overview of the group

BP is a global group, with interests and activities held or operated through subsidiaries, jointly controlled entities or associates established in, and subject to the laws and regulations of, many different jurisdictions. These interests and activities cover three business segments, supported by a number of organizational elements comprising group functions or regions.

The three 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 marketing and trading of gas and power; marketing of liquefied natural gas (LNG); natural gas liquids (NGLs); and low-carbon power generation through our Alternative Energy business. The group provides high-quality technological support for all its businesses through its research and engineering activities.

Group functions serve the business segments, aiming to achieve coherence across the group, manage risks effectively and achieve economies of scale. Each head of region ensures regional consistency of the activities of business segments and group functions and represents BP to external parties.

The group's system of internal control is described in the BP management framework. It is designed to meet the expectations of internal control of the Turnbull Guidance on the Combined Code in the UK and of COSO (committee of the sponsoring organization for the Treadway Commission in the US). The system of internal control is the complete set of management systems, organizational structures, processes, standards and behaviours that are employed to conduct the business of BP and deliver returns to shareholders. The design of the management framework addresses risks and how to respond to them. Each component of the framework is in itself a device to respond to a particular type or collection of risks.

The group strategy describes the group's strategic objectives and the presumptions made by BP about the future. It describes strategic risks that arise from making such presumptions and the actions to be taken to manage or mitigate the risks. The board delegates to the group chief executive responsibility for developing BP's strategy and its implementation through

five-year and annual plans (the group plan) that determine the setting of priorities and allocation of resources. The group chief executive is obliged to discuss with the board, on the basis of the strategy and group plan, all material matters currently or prospectively affecting BP's performance.

As the group's business segments are managed on a global, 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.

We have well-established operations in Europe, the US, Canada, Russia, South America, Australasia, Asia and parts of Africa. Currently, around 70% of the group's capital is invested in Organisation for Economic Co-operation and Development (OECD) countries, with just under 40% of our fixed assets located in the US and around 25% located in the UK and the Rest of Europe.

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

- In Exploration and Production, we have upstream interests in 26 countries. In addition to our drive to maximize the value of our existing portfolio, we are continuing to develop new profit centres. Exploration and Production activities are managed through operating units that 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 & Tobago and the deepwater Gulf of Mexico; and in Russia/Kazakhstan (including our operations in TNK-BP, Sakhalin and LukArco), 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 US and Europe. We market under the Amoco and BP brands in the Midwest, East and Southeast and under the ARCO brand on the West Coast of the US, and under the BP and Aral brands in Europe. We have a long-established supply and trading activity responsible for delivering value across the crude and oil products supply chain. 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 and Castrol brands, including a strong global Lubricants portfolio and other business-to-business marketing businesses (aviation and marine) covering the mobility sectors. We continue to seek opportunities to broaden our activities in growing markets such as China and India.
- In Gas, Power and Renewables, we have a growing marketing and trading business in the US, Canada, UK and continental Europe. Our marketing and trading activities include natural gas, power and NGLs. Our international natural gas monetization activities identify and capture worldwide opportunities for our upstream natural gas resources and are focused on growing natural gas markets, including the US, Canada, Spain and many of the emerging markets of the Asia Pacific region, notably China. We have a significant NGLs processing and marketing business in North America. In 2005, we established BP Alternative Energy, which aims to extend significantly our capabilities in solar, wind, hydrogen power and gas-fired power generation. Alternative Energy has solar production facilities in US, Spain and India and Australia, wind farms in the Netherlands and a substantial portfolio of development projects in the US. We are advancing development of hydrogen power plants and are involved in power projects in the US, UK, Spain and South Korea.

Through non-US subsidiaries or other entities, BP conducts or has conducted limited marketing, licensing and trading activities and technical studies in certain countries subject to US sanctions, in particular 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 of, two fields outside Iran in which NIOC and an affiliated entity have interests. However, BP does not seek to obtain from the government of Iran licences or agreements for oil and gas projects in Iran and does not own or operate any refineries or chemicals plants in Iran.

Acquisitions and disposals

In 2006, there were no significant acquisitions. BP purchased 9.6% of the shares issued under Rosneft's IPO for a consideration of \$1 billion (included in capital expenditure). This represents an interest of around 1.4% in Rosneft. Disposal proceeds were \$6,254 million, which included \$2.1 billion on the sale of our interest in the Shenzi discovery and around \$1.3 billion from the sale of our producing properties on the Outer Continental Shelf of the Gulf of Mexico to Apache Corporation.

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In 2005, there were no significant acquisitions. Disposal proceeds were \$11,200 million, which included 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, disposal proceeds included proceeds from the sale of the group's interest in the Ormen Lange field in Norway.

On 2 November 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 manufactured and marketed 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 above*).

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 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 2004, 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. (*See Refining and Marketing on page 27 for further details.*)

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 included 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 NGLs plants.

Recent development

In March 2007, BP announced its intention to acquire Chevron's Netherlands manufacturing company, Texaco Raffinaderij Pernis B.V., subject to required regulatory approvals. The acquisition includes Chevron's 31% minority shareholding in Nerefco, its 31% shareholding in the 22.5 MW wind farm co-located at the refinery as well as 22.8% shareholding in the TEAM joint venture crude terminal and shareholdings in two local pipelines linking the TEAM terminal to the refinery. Completion is expected by April 2007.

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Exploration and production

Our Exploration and Production business includes upstream and midstream activities in 26 countries, including the US, the UK, Angola, Azerbaijan, Canada, Egypt, Russia, Trinidad & Tobago (Trinidad) and locations within Asia Pacific, Latin 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, Egypt, Russia and Algeria. Major development areas include the deepwater Gulf of Mexico, Azerbaijan, Algeria, Angola, Egypt and Asia Pacific. During 2006, production came from 22 countries. The principal areas of production are Russia, the US, Trinidad, the UK, Latin America, the Middle East, Asia Pacific, Azerbaijan, Angola and Egypt.

Midstream activities involve the ownership and management of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation. 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. Major LNG activities are located in Trinidad, Indonesia and Australia. Further LNG businesses with BP involvement are being built up in Egypt and Angola.

Our oil and gas production assets are located onshore or offshore and include wells, gathering centres, in-field flow lines, processing facilities, storage facilities, offshore platforms, export systems (e.g. transit lines), pipelines and LNG plant facilities.

Key statistics

\$ million

	2006	2005 ^a	2004 ^a
Sales and other operating revenues from continuing operations	52,600	47,210	34,700
Profit before interest and tax from continuing operations	29,629	25,502	18,085
Total assets	99,310	93,447	85,808
Capital expenditure and acquisitions	13,118	10,237	11,002

\$ per barrel

Average BP crude oil realizations ^b	61.91	50.27	36.45
Average BP NGL realizations ^b	37.17	33.23	26.75
Average BP liquids realizations ^{bc}	59.23	48.51	35.39
Average West Texas Intermediate oil price	66.02	56.58	41.49
Average Brent oil price	65.14	54.48	38.27

\$ per thousand cubic feet

Average BP natural gas realizations ^b	4.72	4.90	3.86
Average BP US natural gas realizations ^b	5.74	6.78	5.11

\$ per mmBtu

Average Henry Hub gas price ^d	7.24	8.65	6.13
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Profit before interest and tax from continuing operations includes profit after interest and tax of equity-accounted entities.

- a With effect from 1 January 2006, we transferred the Phu My Phase 3 combined cycle gas turbine plant in Vietnam to the Gas, Power and Renewables segment. The 2005 and 2004 data above has been restated to reflect this transfer.
- 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 activities are divided among existing profit centres – our operations in Alaska, Egypt, Latin America (including Argentina, Bolivia, Colombia and Venezuela), Middle East (including Abu Dhabi, India, Sharjah and Pakistan), North America Gas (onshore US and Canada) and the North Sea (UK, Netherlands and Norway); and new profit centres – our operations in Asia Pacific (Australia, Vietnam, Indonesia and China), Azerbaijan, North Africa (Algeria), Angola, Trinidad and the deepwater Gulf of Mexico; and Russia/Kazakhstan (this includes our operations in TNK-BP, Sakhalin and LukArco).

Operations in Argentina, Bolivia, Abu Dhabi, Kazakhstan and the TNK-BP and Sakhalin operations in Russia, as well as some of our operations in Indonesia and Venezuela, 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.
- 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, total capital expenditure and acquisitions in 2006 was \$13.1 billion (2005 \$10.2 billion and 2004 \$11.0 billion). Capital expenditure in 2006 included our investment in Rosneft's IPO of \$1 billion. There were no significant acquisitions in 2006 or 2005. Acquisitions in 2004 included some \$1.4 billion of additional investment in TNK-BP. Capital expenditure in 2007 is planned to be around \$13 billion. This 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 2006, excluding midstream activities, was \$9,109 million, compared with \$7,678 million in 2005 and \$7,270 million in 2004. This increase reflects the investment we have been making in our new profit centres and the development phase of 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 2006 were \$1,765 million, compared with \$1,266 million in 2005 and \$1,039 million in 2004. 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 41% of 2006 exploration and appraisal costs were directed towards appraisal activity. In 2006, we participated in 85 gross (37 net) exploration and appraisal wells in 14 countries. The principal areas of activity were deepwater Gulf of Mexico, Angola, Egypt, the UK North Sea, Trinidad and Russia (outside TNK-BP).

Total exploration expense in 2006 of \$1,045 million (2005 \$684 million and 2004 \$637 million) included the write-off of unsuccessful drilling activity in the deepwater Gulf of Mexico (\$343 million), in Trinidad (\$85 million), in Turkey (\$80 million), onshore North America (\$44 million) and others (\$16 million).

In 2006, we obtained upstream rights in several new tracts, which include the following:

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In the Gulf of Mexico, we were awarded 101 blocks (BP 100%) through the Outer Continental Shelf Lease Sales 198 and 200.

□ In India, we were awarded (BP 100%) the Coal Bed Methane block BB-CBM-2005/III located in the Birbhum district of West Bengal.

□ In Pakistan, we were awarded three new blocks (BP 100%), covering approximately 20,000 km² of the offshore Indus delta.

In early 2007:

□ In Oman, we signed a production-sharing agreement to appraise and develop the Khazzan/Makarem gas fields.

In 2006, we were involved in a number of discoveries. In most cases, reserves bookings from these fields will depend on the results of ongoing

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technical and commercial evaluations, including appraisal drilling. Our most significant discoveries in 2006 included the following:

- In Angola, we made further discoveries in the ultra deepwater (greater than 1,500 metres) in Block 31 (BP 26.7% and operator) with Urano, Titania and Terra wells, bringing the total number of discoveries in Block 31 to 12.
- In the deepwater Gulf of Mexico, we made a discovery with the Kaskida well.

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 usually 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, typically within three years. Where, on occasion, the group decides to book reserves where development is scheduled to commence beyond three years, these reserves will be booked only where they satisfy the SEC's criteria for attribution of proved status. 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 reserves bookings that forms part of a holistic and integrated system of internal control. BP's process to manage reserves bookings has been centrally controlled for more than 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 reserves verification and approval process of the group's reserves estimates and the timely reporting of the related financial impacts of proved reserves changes. These officers of the company are responsible for carrying out verification of proved reserves 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 reserves 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 31 December 2006, 2005 and 2004 and reserves changes for each of the three years then ended are set out in the

Supplementary information on oil and natural gas section beginning on page 194. 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 the group's oil and gas reserves held in consolidated companies have been estimated by the group's petroleum engineers. Of the equity-accounted volumes in 2006, 17% were based on estimates prepared by group petroleum engineers and 83% were based on estimates prepared by independent engineering consultants, although all the group's oil and gas reserves held in equity-accounted companies are reviewed by the group's petroleum engineers before making the assessment of volumes to be booked by BP.

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

At the end of 2006, BP adopted the SEC rules for estimating reserves for all accounting and reporting purposes. Previously, BP applied the UK accounting rules contained in the Statement of Recommended Practice "Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities" (UK SORP). These changes are explained in Financial statements - Note 3 on page 102. The company's proved reserves estimates for the year ended 31 December 2006 reflect year-end prices and application of 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. Consequently, these reserves quantities differ from those that would be reported under application of the UK SORP. The 2006 year-end marker prices used were Brent \$58.93/bbl (2005 \$58.21/bbl and 2004 \$40.24/bbl) and Henry Hub \$5.52/mmBtu (2005 \$9.52/mmBtu and 2004 \$6.01/mmBtu). The other 2006 movements in proved reserves are reflected in the tables showing movements in oil and gas reserves by region in Financial statements - Supplementary information on oil and natural gas on pages 194-195.

Total hydrocarbon proved reserves, on an oil equivalent basis and excluding equity-accounted entities, comprised 13,163mmboe at 31 December 2006, a decrease of 6.1% compared with 31 December 2005. Natural gas represents about 55% of these reserves. This reduction includes net sales of 227mmboe, largely comprising a number of assets in Latin America, the UK and the US.

The proved reserves replacement ratio, excluding equity-accounted entities, was 34% (2005 68% and 2004 78%). The proved reserves replacement ratio (also known as the production replacement ratio) is the extent to which production is replaced by proved reserves additions. This

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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 reserves replacement ratio, including sales and purchases of reserves-in-place but excluding equity-accounted entities, was 11% (2005 40% and 2004 64%). 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 2006, net additions to the group's proved reserves (excluding sales and purchases of reserves-in-place and equity-accounted entities) amounted to 329mmboe, principally through improved recovery from existing fields. Of the reserves additions through improved recovery from, and extensions to, existing fields and discoveries of new fields, approximately half are associated with new projects and are proved undeveloped reserves additions. The remainder are in existing developments where they represent a mixture of proved developed and proved undeveloped reserves. Major new development projects typically take one to four years from the time of initial booking to the start of production. The principal reserves additions were in the UK (Devenick, Foinaven), the US (San Juan, Seminole, Great White, Horn Mountain, Mars) and Angola (Rosa, Greater Plutonio).

Total hydrocarbon proved reserves, on an oil equivalent basis for equity-accounted entities alone, comprised 4,537mmboe at 31 December 2006, an increase of 17.2% compared with 31 December 2005. Natural gas represents about 14% of these reserves. The proved reserves replacement ratio for equity-accounted entities alone was 272% (2005 151% and 2004 114%) and the proved reserves replacement ratio for equity-accounted entities alone but including sales and purchases of reserves-in-place was 239% (2005 141% and 2004 170%).

Additions to proved developed reserves in 2006 for subsidiaries were 675mmboe, including sales and purchases. This included some reserves that were previously classified as proved undeveloped. The proved

developed reserves replacement ratio (including both sales and purchases of reserves-in-place) was 70% (2005 63% and 2004 70%).

Additions to proved developed reserves in 2006 for equity-accounted entities were 936mmboe. This included some reserves that were previously classified as proved undeveloped. The proved developed reserves replacement ratio (including both sales and purchases of reserves-in-place) was 195% (2005 99% and 2004 180%).

Our total hydrocarbon production during 2006 averaged 2,629 thousand barrels of oil equivalent per day (mboe/d) for subsidiaries and 1,297mboe/d for equity-accounted entities, a decrease of 3.3% and an increase of 0.1% respectively compared with 2005. For subsidiaries, 36% of our production was in the US and 16% in the UK. For equity-accounted entities, 75% of production was from TNK-BP.

Total production for 2007 is expected to remain broadly the same as in 2006 after allowing for the impact on 2007 of divestments made in 2006. This estimate is based on the group's asset portfolio at 1 January 2007, expected start-ups in 2007 and Brent at \$60/bbl, before any 2007 disposal effects and before any effects of prices above \$60/bbl on volumes in PSAs.

The anticipated decline in production volumes from subsidiaries in our existing profit centres is partly mitigated by the development of new projects and the investment in incremental reserves in and around existing fields. We expect that this overall decline in production from subsidiaries in our existing profit centres will be more than compensated for by strong increases in production from subsidiaries in our new profit centres over the next few years. Production in our equity-accounted joint venture TNK-BP is expected to remain broadly constant to 2009.

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 Liquidity and capital resources on page 47.*)

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The following tables show BP's estimated net proved reserves as at 31 December 2006.

Estimated net proved reserves of liquids at 31 December 2006^{a b}			million barrels
	Developed	Undeveloped	Total
UK	458	146	604
Rest of Europe	189	97	286
USA	1,916	1,292	3,208
Rest of Americas	130	237	367 ^c
Asia Pacific	67	86	153
Africa	193	512	705
Russia	□	□	□
Other	88	482	570
Group	3,041	2,852	5,893
Equity-accounted entities			3,888 ^d

Estimated net proved reserves of natural gas at 31 December 2006^{a b}			billion cubic feet
	Developed	Undeveloped	Total
UK	1,968	825	2,793
Rest of Europe	242	56	298
USA	10,438	4,660	15,098
Rest of Americas	3,932	9,194	13,126 ^e
Asia Pacific	1,359	5,202	6,561
Africa	1,032	1,675	2,707
Russia	□	□	□
Other	331	1,254	1,585
Group	19,302	22,866	42,168
Equity-accounted entities			3,763 ^f

Net proved reserves on an oil equivalent basis (mmboe)

□ Group	13,163
□ Equity-accounted entities	4,537

- a Net proved reserves of crude oil and natural gas, stated as at 31 December 2006, 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 that 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 analogous 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 2006, BP had proved reserves in 22 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, Atlantis and Thunder Horse, are expected to begin production by the end of 2007 and by the end of 2008 respectively. Two other fields are in the early stages of development.

- c Includes 23 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
- d Includes 179 million barrels of crude oil in respect of the 6.29% minority interest in TNK-BP.
- e Includes 3,537 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
- f Includes 99 billion cubic feet of natural gas in respect of the 7.77% minority interest in TNK-BP.

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The following tables show BP's production by major field for 2006, 2005 and 2004.

Production	Field or Area	Interest	thousand barrels per day		
			BP net share of production ^a		
		%	2006	2005	2004
Alaska	Prudhoe Bayb	26.4	71	89	97
	Kuparuk	39.2	57	62	68
	Northstarb	98.6	38	46	49
	Milne Pointb	100.0	31	37	44
	Other	Various	27	34	37
Total Alaska			224	268	295
Lower 48 onshorec	Various	Various	125	130	142
Gulf of Mexico deepwaterc	Na Kikab	50.0	41	44	27
	Horn Mountainb	66.6	23	26	41
	Kingb	100.0	28	24	26
	Mars	28.5	19	21	35
	Ursa	22.7	21	19	29
	Other	Various	63	64	47
Gulf of Mexico Shelfc	Other	Various	3	16	24
Total Gulf of Mexico			198	214	229
Total USA			547	612	666
UK offshorec	ETAPd	Various	49	49	55
	Foinavenb	Various	37	39	48
	Magnusb	85.0	30	30	34
	Schiehallion/Loyalb	Various	26	28	39
	Hardingb	70.0	17	22	27
	Andrewb	62.8	7	12	12
	Other	Various	69	75	89
Total UK offshore			235	255	304
Onshore	Wytch Farmb	67.8	18	22	26
Total UK			253	277	330
Netherlands	Various	Various	1	1	1
Norway	Valhallb	28.1	21	25	25
	Draugen	18.4	15	20	27
	Ulab	80.0	14	17	16
	Other	Various	10	12	8
Total Rest of Europe			61	75	77
Angola	Kizomba A	26.7	54	56	16
	Girassol	16.7	17	34	31
	Xikomba	26.7	4	10	18
	Other	Various	58	28	6
Australia	Various	15.8	34	36	36
Azerbaijan	Azeri-Chirag-Gunashlib	34.1	145	76	39
Canadac	Various	Various	8	10	11
Colombia	Variousb	Various	34	41	48
Egypt	Various	Various	42	47	57
Trinidad & Tobagoc	Variousb	100.0	40	40	59
Venezuelac	Various	Various	26	55	55
Otherc	Various	Various	28	26	31

Total Rest of World			490	459	407
Total groupe			1,351	1,423	1,480
Equity-accounted entities (BP share)					
Abu Dhabif	Various	Various	163	148	142
Argentina □ Pan American Energy	Various	Various	69	67	64
Russia □ TNK-BPc	Various	Various	876	911	831
Otherc	Various	Various	16	13	14
Total equity-accounted entities			1,124	1,139	1,051

a Net of royalty, whether payable in cash or in kind.

b BP-operated.

c In 2006, BP divested its producing properties on the Outer Continental Shelf of the Gulf of Mexico and its interest in the Statfjord oil and gas field in the UK. Our interests in the Boqueron, Desarrollo Zulia Occidental (DZO) and Jusepin projects in Venezuela were reduced following a decision by the Venezuelan government. TNK-BP disposed of its non-core interests in the Urdmurtneft assets. 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 US. 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.

d Volumes relate to six BP-operated fields within ETAP. BP has no interests in the remaining three ETAP fields which are operated by Shell.

e Includes 55 thousand net barrels of oil equivalent per day (mboe/d) of NGLs from processing plants in which BP has an interest (2005 58mboe/d and 2004 67mboe/d).

f The BP group holds proportionate interests, through associates, in onshore and offshore concessions in Abu Dhabi expiring in 2014 and 2018, respectively.

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Natural gas			%	million cubic feet per day		
				BP net share of production ^a		
Production	Field or Area	Interest		2006	2005	2004
Lower 48 onshoreb	San Juanc	Various		765	753	772
	Arkomac	Various		225	198	183
	Hugotonc	Various		137	151	158
	Tuscaloosac	Various		86	111	96
	Wamsutterc	70.5		113	110	105
	Jonahc	65.0		133	97	114
	Other	Various		461	465	514
	Total Lower 48 onshore 1,920 1,885 1,942					
Gulf of Mexico deepwater ^b	Na Kika ^c	50.0		97	133	133
	Marlin ^c	78.2		16	52	43
	Other Various	210	235 313			
	Gulf of Mexico Shelf ^b Other Various 66 160 240					
	Total Gulf of Mexico 389 580 729					
	Alaska Various	Various		67	81	78
	Total USA			2,376	2,546	2,749
	UK offshore ^b Braes ^d Various 101 165 147					
	Bruce ^c	37.0		107	161	163
	West Sole ^c	100.0		56	55	67
Marnock ^c	62.0			42		
	47 70	Britannia 9.0		42	46	54
	Shearwater 27.5			31	37	76
	Armada 18.2			28	30	50
	Other Various			529		
	549 547	Total UK		936	1,090	1,174
	Netherlands P/18-2 ^c	48.7		23	25	34
	Other Various			33	37	46
	Norway Various	Various		35	46	45
	Total Rest of Europe			91	108	125
Australia Various	15.8			364	367	308
	Canada ^b Various	Various		282	307	349
	China Yacheng ^c	34.3		102	98	99
	Egypt Ha ^c	50.0		99	106	80
	Other Various			172	83	115
	Indonesia ^b Sanga-Sanga(direct) ^c	26.3		84	110	137
	Other ^c	46.0		80	128	144
	Sharjah Sajaa ^c	40.0		111	113	103
	Other	40.0		9	10	14
	Trinidad & Tobago ^b Kapok ^c	100.0		946	1,005	553
Mahogany ^c	100.0			321	303	453
	Amherstia ^c	100.0		176	289	408
	Parang ^c	100.0		120	154	137
	Immortelle ^c	100.0		219	132	172
	Cassia ^c	100.0		30	83	85
	Other ^c	100.0		453	21	111
	Other ^b Various			441	459	308
	Total Rest of World			4,009	3,768	3,576
	Total group ^e			7,412	7,512	7,624
	Equity-accounted entities (BP share)					
Argentina				362	343	317
	Pan American Energy	Various		362	343	317
	Russia			544	482	458
	TNK-BP	Various		544	482	458
	Other ^b Various	Various		99	87	104
	Total equity-accounted entities ^b			1,005	912	879

a Net of royalty, whether payable in cash or in kind.

b In 2006, BP divested its producing properties on the Outer Continental Shelf of the Gulf of Mexico and its interest in the Statfjord oil and gas field in the UK. Our interests in the Boqueron, Desarrollo Zulia Occidental (DZO) and Jusepin projects in Venezuela were reduced following a decision by the Venezuelan government. TNK-BP disposed of its non-core interests in the Urdmurtneft assets. In 2005, BP divested the Teak, Samaan and Pouli 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 US. 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.

c BP-operated.

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

e 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.

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United States

2006 liquids production at 547 thousand barrels per day (mb/d) decreased 11% from 2005, while natural gas production at 2,376 million cubic feet per day (mmcf/d) decreased 7% compared with 2005.

Crude oil production decreased 63mb/d from 2005, with production from new projects being offset by divestments and natural reservoir decline. The NGLs component of liquids production remained essentially flat compared with 2005, with a slight decline of 2mb/d. Gas production was lower (170mmcf/d) because of divestments and natural reservoir decline.

Development expenditure in the US (excluding midstream) during 2006 was \$3,579 million, compared with \$2,965 million in 2005 and \$3,247 million in 2004. The annual increase is the result of various development projects in progress.

On 19 April 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 major part of the sale was completed in June 2006 after receiving regulatory approval. In the third quarter of 2006, we completed the sale of our remaining Gulf of Mexico Shelf assets that were subject to pre-emption rights. BP retained certain decommissioning obligations related to the disposed assets.

Our activities within the US take place in three main areas. Significant events during 2006 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 US. In 2006, our deepwater Gulf of Mexico crude oil production was 195mb/d and gas production was 323mmcf/d.

Significant events were:

- Offshore repair work on the Thunder Horse platform (BP 75% and operator) was completed during 2006. However, tests conducted during the commissioning of the platform revealed metallurgical failure in components of the subsea system. In September 2006, we announced our plan to retrieve and replace all the subsea components we believed could be at risk. We currently estimate that this will cost around \$650 million (BP net). Production is expected to start up by the end of 2008.
- The Mars platform (BP 28.5%) suffered heavy damage from Hurricane Katrina in August 2005. Production resumed in May 2006 and was 190mboe/d gross by September 2006, a 20% increase over pre-Katrina rates.
- Expansion of the Mars and Na Kika fields also continued during 2006 and first production from these projects is expected in 2007.
- Progress continued on the Atlantis project (BP 56% and operator) during 2006. The semi-submersible platform will be the deepest moored floating production facility in the world in approximately 7,100 feet of water. First oil is expected by the end of 2007.
- On 31 August 2006, we announced a significant oil exploration discovery on the Kaskida prospect in approximately 5,900 feet of water.
- Development of the King Subsea Pump project (BP 100% and operator) continued during 2006, with first production expected by the end of 2007. This is the first subsea multi-phase pump application in water depths greater than 3,000 feet.
- In July 2006, we completed the sale of our 28% interest in the Shenzi discovery to Repsol for \$2,145 million.

Lower 48 states

In the Lower 48 states (Onshore), our 2006 natural gas production was 1,920mmcf/d, which was up 2% compared with 2005. Liquids production was 125mb/d, down 4% compared with 2005 as a result of normal field decline. In 2006, we drilled approximately 330 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 218mboe/d in 2006.
- In the Gulf Coast and Mid-Continental basins (Kansas, Louisiana, Oklahoma and Texas), our assets produced 183mboe/d in 2006.
- 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 10 times higher than more conventional techniques and per-well recoveries some five times higher.

Significant events were:

- Drilling continued during 2006 on the Wamsutter natural gas expansion project. The multi-year drilling programme is expected to increase production significantly by the end of 2010. We are currently testing horizontal fracturing technology and carrying out wireless seismic studies on the reservoir.

- In January 2007, we announced our investment of up to \$2.4 billion over the next 13 years in the Coal Bed Methane Field development project in the San Juan Basin of Colorado. The project includes the drilling of more than 700 wells, nearly all from existing well sites, and the installation of associated field facilities.
- In October 2006, we completed the sale of five onshore properties in South Louisiana to Swift Energy for approximately \$160 million.

Alaska

In Alaska, BP net crude oil production in 2006 was 224mb/d, a decrease of 16% from 2005, due to mature field decline and operational issues associated with transit pipelines described below.

BP operates 13 North Slope oil fields (including Prudhoe Bay, Northstar and Milne Point) and four North Slope pipelines and owns a significant interest in six other producing fields. Our 26.4% interest in the Prudhoe Bay natural gas resource is a large undeveloped source of natural gas.

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.

Significant events were:

- BP, along with ExxonMobil, ConocoPhillips and the Executive Branch of the State of Alaska, reached agreement on a gas pipeline fiscal contract. Two special sessions of the legislature called by the former governor ended without legislative ratification of the contract. The change of governor, which took place in December 2006, has temporarily delayed continued negotiations with the State of Alaska until a clear process leading to ratification of the gas pipeline fiscal contract is defined by the new administration. BP stands ready to execute a modified fiscal contract that is agreeable to all the parties.
- The State of Alaska significantly increased production taxes by adopting a new Petroleum Production Tax (PPT) bill on 19 August 2006, effective from 1 April 2006. The key terms of the PPT include a 22.5% oil tax rate with capital credits and a clause whereby the oil tax rate increases as the net margin rises above \$40/bbl.
- On 27 November 2006, the State of Alaska Department of Natural Resources (DNR) issued a decision regarding the Plan of Development (POD) submitted by ExxonMobil on behalf of the Point Thompson Unit owners (BP 32%) on 18 October 2006. The DNR decision was to reject the modified POD, deny the proposed settlement of the expansion lease acreage and terminate the Point Thompson Unit. BP, along with the other owners, is studying options available in response to this decision. BP intends to pursue vigorously the retention of its interest in the Point Thompson Unit and remains committed to its development in conjunction with our broader gas strategy and the proposal to construct a gas pipeline from Alaska, through Canada, to the Midwest US.
- Alaska viscous and heavy oil assets produced their 100 millionth barrel (gross) in November 2006. West Sak 1J Phase 1 viscous project has drilled more than half the planned 31 development wells, Milne Point is planning the NW Schrader Bluff winter appraisal programme and the Orion Phase II sanction in Prudhoe Bay is expected in the first quarter of 2007. Orion Phase II completes GC-2 viscous oil facility modifications and develops eight additional producer wells and 22 injector wells; first oil is planned for 2009.
- On 2 March 2006, a transit pipeline in the Western operating area of the Prudhoe Bay field was discovered to have spilled approximately 4,800 barrels of crude oil over approximately two acres. The processing facility that feeds into the transit line was immediately shut down. An investigation team determined that the leak was caused by internal corrosion. Spill clean-up was completed and business operations resumed in April 2006 using a separate bypass line. (See also *Environmental Protection* □ *Health, Safety and Environmental Regulation* on page 35.)

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- On 7 August 2006, an orderly and phased shutdown of the Eastern Operating Area of the Prudhoe Bay oil field began following the discovery of unexpected corrosion and a small spill from a Prudhoe Bay oil transit line. In September, we determined that the oil transit lines in the Eastern Operating Area of Prudhoe Bay could be returned to service for the purposes of in-line inspection. By the end of October we had returned to service all three flow stations previously shut down.
- Current production from Prudhoe Bay is more than 400,000 barrels of oil and natural gas liquids per day (gross). BP has a 26.4% interest in the Prudhoe Bay field.
- In response to the recent corrosion discoveries, BP has decided to replace the main oil transit lines (16 miles) in both the Eastern and Western Operating Areas of Prudhoe Bay. In addition, BP plans to spend over \$550 million (net) over the next two years on integrity management in Alaska. BP has retained three eminent corrosion experts to evaluate independently and make recommendations for improving the corrosion programme in Alaska. BP has also asked an independent ombudsman to undertake a review of worker allegations raised on the North Slope of Alaska since the acquisition of ARCO in 2000 to determine whether the problems have been addressed and rectified.
- In February 2007, BP temporarily shut down its Northstar production facility to repair welds in the low pressure gas piping system. BP is currently finalising inspections and has begun repairs.

United Kingdom

We are the largest producer of oil and second largest producer of gas in the UK. BP remains the largest overall producer of hydrocarbons in the UK. In 2006, total liquids production was 253mb/d, a 9% decrease on 2005, and gas production was 936mmcf/d, a 14% decrease on 2005. This decrease in production was driven by the natural decline, operational issues and lower seasonal gas demand. Our activities in the North Sea are focused on safe operations, efficient delivery of production and midstream operations, in-field drilling and selected new field developments. Our development expenditure (excluding midstream) in the UK was \$794 million in 2006, compared with \$790 million in 2005 and \$679 million in 2004.

Significant events were:

- Drilling continued during 2006 on the Clair Phase 1 development (BP 28.6% and operator) programme and is scheduled to continue through 2008.
- In September 2006, BP reached an agreement, subject to Department of Trade and Industry (DTI) approval, to acquire acreage in the UK

Central North Sea that contains two discovered fields and further exploration potential.

- BP and its partner approved the front end engineering and design for the Harding Area Gas Project (BP 70% and operator) in July 2006.

This represents the first stage of a development project to allow the production of gas from the Harding area and prolong the life of the field beyond 2015.

- Progress continued during the year on the Magnus Expansion Project (BP 85% and operator), with first oil achieved in October 2006.
- The UK government approved the North West Hutton decommissioning programme in April 2006. BP, on behalf of the owners of North West Hutton (BP 26% and operator), awarded a contract in October 2006 for the offshore removal and onshore recycling of the installation. Detailed engineering work for removal has begun. Platform removal is expected to start in 2008 and to be completed by the end of 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%. This tax increase became law in July 2006, with effect from 1 January 2006.
- In March 2006, we reached agreement for the sale of our 4.84% interest in the Statfjord oil and gas field. This sale was completed in June 2006.

Rest of Europe

Development expenditure, excluding midstream, in the Rest of Europe was \$214 million, compared with \$188 million in 2005 and \$262 million in 2004.

Norway

In 2006, our total production in Norway was 66mboe/d, a 20% decrease on 2005. This decrease in production was driven by natural decline.

Significant activities were:

- Progress on the Valhall (BP 28.1% and operator) redevelopment project continued during 2006. A new platform is scheduled to become operational in 2010, with expected oil production capacity of 150mb/d and gas handling capacity of 175mmcf/d.

- Drilling continued through 2006 on the Valhall flank development and water injection projects. The flank drilling programme was completed in September 2006 and water injection drilling will continue during 2007.
- 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 was completed on 1 February 2007 to the Abu Dhabi National Energy Company, TAQA.

Rest of World

Development expenditure, excluding midstream, in Rest of World was \$4,522 million in 2006, compared with \$3,735 million in 2005 and \$3,082 million in 2004.

Rest of Americas

Canada

- In Canada, our natural gas and liquids production was 57mboe/d in 2006, a decrease of 10% compared with 2005. The year-on-year decrease in production is mainly due to natural field decline.
- BP has been successful in obtaining new licences in British Columbia and Alberta land sales. The acquired acreage will form part of the Noel tight gas development project in north-eastern British Columbia. The project will involve drilling up to 180 horizontal wells and innovative fracturing technology to develop the remainder of the resources.

Trinidad

- In Trinidad, natural gas production volumes increased by 14% to 2,265mmcf/d in 2006. The increase was driven by higher demand due to the ramp-up of Atlantic LNG Train 4. Liquids production declined by 2mb/d (5%) to 38mb/d in 2006.
- Cannonball (BP 100%), Trinidad's first major offshore construction project executed locally, started production in March 2006. Production increased during the year and the asset is currently providing gas for the Atlantic LNG trains.
- BP sanctioned the development projects for Red Mango (BP 100%) in April 2006 and for Cashima (BP 100%) in August 2006. First production is expected by the end of 2007 and in 2008 respectively.

Venezuela

- In Venezuela, our 2006 liquids production reduced by 25mb/d compared with 2005, mainly as a result of the enforced reduction of our interests in the non-BP-operated Jusepin property and the Boqueron and Desarrollo Zulia Occidental (DZO) reactivation projects, which BP operated until 31 March 2006 under operating service agreements on behalf of the state oil company, Petroleos de Venezuela S.A. (PDVSA).
- In August 2006, BP signed conversion agreements to co-operate with PDVSA in setting up incorporated joint ventures in which PDVSA would be the majority shareholder. The structures for the incorporated joint ventures were established in December 2006 and these are now the operators of the Boqueron and DZO properties.

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- In December 2006, BP, in common with the other partners in the Jusepin property, reached agreement with PDVSA for compensation in return for the relinquishment of our interest in the property.
- Cerro Negro is a non-BP-operated property that is a heavy oil project from which production is sold directly by BP. The Venezuelan government has communicated its intention of converting this strategic association to an incorporated joint venture. It is too early to determine the effect of this.
- In 2005, changes were made by the Venezuelan government to increase corporate income taxes from 34% to 50% on those companies operating under operating service agreements. Changes were also made in 2006 to the taxation of oil extraction companies, such as Cerro Negro. From 1 June 2006, a new extraction tax at a maximum rate of 33.33% was introduced (the existing royalty of 16.67% can be offset against the new extraction tax) and, on 25 September 2006, the corporate income tax rate was raised from 34% to 50% with effect from 1 January 2007.

Colombia

- In Colombia, BP's net production averaged 50mboe/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 gross since operations began in 1992.
- In December 2006, the corporate income tax rate was reduced from its current rate of 35% to 34% from 1 January 2007 and to 33% from 1 January 2008.

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 since it is jointly controlled. In 2006, total production of 145mboe/d represented an increase of 7% over 2005, with oil increasing by 4% and gas by 10%. 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 60mb/d, compared with 58mb/d in 2005. 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 November 2006, PAE and all other oil and gas companies with operations in Bolivia entered into agreements with the state-owned oil company Yacimientos Petrolíferos Fiscales Bolivianos (YPFB) that establish governmental control over the country's hydrocarbon resources. The agreements have been approved by the Bolivian Congress. YPFB will be responsible for marketing all hydrocarbons produced in Bolivia and for determining the terms of sales contracts.

Africa

Algeria

- BP, through its joint operatorship of In Salah Gas with Statoil and the Algerian state company, Sonatrach, supplied 300bcf (gross) of gas to markets in Algeria and southern Europe during 2006. The carbon dioxide (CO₂) capture system, part of the In Salah project (BP 33.15%), is one of the world's largest CO₂ capture projects.
- BP, through its joint operatorship of In Amenas with Statoil and Sonatrach, completed the development of the In Amenas project (BP 12.5%). First production was achieved in June 2006.
- From 1 August 2006, a windfall profit tax was announced that applies to certain producers when the monthly average price of a barrel of oil exceeds \$30. At present, the only asset of BP affected by this is the In Amenas project.

Angola

- In Block 15 (BP 26.7%), development of Kizomba C commenced in the first quarter of 2006. Development of Kizomba A Phase II continued, with first production planned for the end of 2007.
- In Block 17 (BP 16.7%), development activities were completed and the FPSO moored on the Dalia project. First production commenced in

December 2006. Development on the Rosa project, a tie-back to the Girassol hub, continued, with first production expected by the end of 2007.

- In Block 18 (BP 50% and operator), work has continued on the Greater Plutonio development in line with expectations to commence production by the end of 2007.
- In Block 31 (BP 26.7% and operator), three additional discoveries were made in 2006. There have been a total of 12 discoveries that are at various stages of assessment of commercial viability.
- We are participating in the Angola LNG project (BP 13.6%).

Egypt

- In Egypt, the Gulf of Suez Petroleum Company (GUPCO) (BP 50%), a joint venture operating company between BP and the Egyptian General Petroleum Corporation, carries out our operated oil and 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 40 fields.
- The Tensah redevelopment project was completed and production achieved in the second quarter of 2006.
- Progress continued on the Saqqara field (BP 100%) development project, with first production expected in the first quarter of 2008.
- In June 2006, the Egyptian Natural Gas Holding Corporation (EGAS), BP, SEGAS and Eni signed a framework agreement marking a major step forward for the development of the second liquefied natural gas (LNG) export train at the Damietta site on the Egyptian Mediterranean coast.

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 2006, 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 LNG is expected by the end of 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 2006, natural gas production was 392mmcf/d gross, an increase of 13% over 2005. This increase was mainly due to higher demand resulting from continuing growth in the economy. 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%).

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 2006, progress continued on the construction of a fifth LNG train (4.7 million tonnes a year design capacity), with first throughput expected in 2008.

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Russia

TNK-BP

- TNK-BP, a joint venture between BP (50%) and Alfa Group and Access-Renova (AAR) (50%), is an integrated oil company operating in Russia and the Ukraine. The TNK-BP group's major assets are held in OAO TNK-BP Holding. Other assets include the BP-branded retail sites in Moscow and the Moscow region, OAO Russia Petroleum and the OAO Slavneft group. The workforce is about 70,000 people.
- BP's investment in TNK-BP is held by the Exploration and Production business and the results of TNK-BP are accounted for under the equity method in this segment.
- TNK-BP has proved reserves of 6.1 billion boe (including its 49.9% equity share of Slavneft), of which 4.8 billion are developed. In 2006, average liquids production was 1.9mmboe/d, a decrease of just over 2% compared with 2005, reflecting the disposal of the Urdmurt and Saratov assets in 2006 and 2005. The production base is largely centred in West Siberia (Samotlor, Nyagan and Megion), which contributes about 1.4mmboe/d, together with Volga Urals (Orenburg) contributing some 0.4mmboe/d. About 50% 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 0.6 million barrels a day (28 million tonnes a year). In retail, TNK-BP operates more than 1,600 filling stations in Russia and the Ukraine, with a share of the Moscow retail market in excess of 20%.
- During 2006, four of TNK-BP's licences were extended by 25 years including two key licences covering the Samotlor field and the Khokhryakovskoye and Permyakovskoye licences.
- In October, TNK-BP's subsidiary Russia Petroleum received a letter from the Russian authorities alleging a number of violations of the conditions related to a licence covering part of the Kovykta field in East Siberia. In February 2007, the status of the licence was reviewed by the authorities, who we anticipate will issue formal findings shortly. Russia Petroleum continues to discuss this matter with the authorities in order to address any outstanding concerns.
- In November, following a review of the results of an inspection by the licensing authorities, regional prosecutors made a request for revocation of the two licences held by TNK-BP subsidiary Rospan International on grounds of violation of licence conditions and applicable legislation. Following discussion with the licensing authorities, renewal was granted of certain documents associated with the licences for which TNK-BP had previously applied. In addition, Rospan presented a plan to rectify the licence non-compliances, following which the licensing authorities have granted a six-month period to fulfil this plan.
- On 23 October 2006, TNK-BP received decisions from the Russian tax authorities in relation to the tax audits of certain TNK-BP group companies for the years 2002 and 2003, resulting in a payment by TNK-BP of approximately \$1.4 billion in settlement of these claims.
At the present time, BP believes that its provisions are adequate for its share of any liabilities arising from these and other outstanding tax decisions not covered by the indemnities provided by our co-venturers in respect of historical tax liabilities related to assets contributed to the joint venture.
- In August 2006, TNK-BP completed the sale of its interest in OAO Udmurtneft to Sinopec.
- In January 2007, TNK-BP announced the acquisition of Occidental Petroleum's 50% interest in the West Siberian joint venture, Vanyoganneft, for \$485 million. The transaction is expected to close during the first quarter of 2007, subject to Russian regulatory approvals. On completion of the purchase, TNK-BP will own 100% of the Vanyoganneft asset.

Sakhalin

- BP participates in exploration activity through Elvanyneftegas (BP 49%), an equity-accounted joint venture with Rosneft in Sakhalin, where three discoveries have been made. Exploratory drilling continued in 2006 and preliminary work is under way to prepare for development if commercial reserves are discovered. Further drilling is planned during 2007.

Other

- In July 2006, BP purchased 9.6% of the shares issued in Rosneft's IPO for \$1 billion. This represents an interest of around 1.4% in Rosneft.

Other

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. Phase 2 of the Azeri project delivered first oil from the West Azeri platform to Sangachal terminal on 3 January 2006 and was completed on 21 October 2006 with the delivery of first oil from the East Azeri platform to Sangachal, four months ahead of schedule. Phase 3 of the project, which will develop the deepwater Gunashli area of ACG, remains on schedule to begin production in 2008.
- Construction and the Stage 1 pre-drill programme of the project to develop the Shah Deniz natural gas field (BP 25.5% and operator) were completed in 2006, with first gas in December 2006.

Middle East and Pakistan

- Production in the Middle East consists principally 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 2006, production in Abu Dhabi was 164mb/d, up 11% from 2005 as a result of capacity enhancements.
- 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 2006.
- In July 2006, BP was awarded three offshore blocks in Pakistan's offshore Indus Delta. The blocks cover an area of approximately 20,000km² and include the right to operate any commercially viable discoveries.
- In January 2007, we were awarded development rights to the Khazzan/ Makarem fields in Oman. These provide access to a significant volume of tight gas resource in place, which we believe can be developed using the same technology as we are currently deploying at our Wamsutter field in the US.

India

- In November 2006, BP signed a PSA with the Indian government to explore for coal bed methane in the Birbhun district of India's eastern West Bengal state.

Midstream activities

Oil and natural gas transportation

The group has direct or indirect interests in certain crude oil transportation systems, the principal ones being the Trans Alaska Pipeline System (TAPS) in the US 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, which was fully commissioned in July 2006. 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 (see page 23). Revenue is earned on pipelines through charging tariffs. Our gas marketing business is included in our Gas, Power and Renewables segment (see page 31).

Activity in oil and natural gas transportation during 2006 included:

Alaska

- BP owns a 46.9% interest in TAPS, with the balance owned by four other companies. Production transported by TAPS from Alaska North Slope fields averaged 748mb/d during 2006.
- The use of US-built and US-flagged ships is required when transporting Alaskan oil to markets in the US. In September 2006, BP completed the replacement of its US-flagged fleet with the delivery of its fourth ship, the Alaska Legend. BP had contracted for the delivery of four 1.3 million-barrel-capacity double-hulled tankers for use in transporting

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North Slope oil to West Coast refineries. BP took delivery of the first three tankers between August 2004 and November 2005. As existing ships were retired, the replacements were constructed in accordance with the Oil Pollution Act of 1990. For discussion of the Oil Pollution Act of 1990, see Environmental Protection ☐ Maritime oil spill regulations on page 37.

- ☐ Work progressed during 2006 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. Start-up of the first pump station is expected to occur in the first quarter of 2007, with the second expected to be online by the end of 2007. The remaining two reconfigured pump stations are expected to come online sequentially after 2007.
- ☐ 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 1 July 2003 that are consistent with its 2002 Order requiring refunds to be made to TAPS shippers of intrastate 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. BP will continue to collect its TSM-based interstate tariffs; however, our tariffs are subject to refund depending on the outcome of the challenges. Interstate transport makes up roughly 93% of total TAPS throughput.

North Sea

- ☐ FPS (BP 100%) is an integrated oil and NGLs transportation and processing system that handles production from more than 50 fields in the Central North Sea. The system has a capacity of more than 1mmb/d, with average throughput in 2006 at 545mb/d. In January 2007, FPS completed the tying in of the Buzzard field, which is expected to be a significant user of FPS capacity.
- ☐ 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 1.7bcf/d to a natural gas terminal at Teesside in north-east England. CATS offers natural gas transportation and processing services. In 2006, throughput was 1.1bcf/d (gross), 326mmcf/d (net).
- ☐ In addition, BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe oil and 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 750,000 barrels of oil a day by the end of 2007 from the BP-operated ACG oil field in the Caspian Sea to the eastern Mediterranean port of Ceyhan. Loading of the first tanker at Ceyhan occurred in June 2006 and the official inauguration of the Turkish section of the BTC oil export pipeline, the new Ceyhan marine export terminal and the full BTC pipeline export system was held on 13 July 2006.
- ☐ The South Caucasus Pipeline for the transport of gas from Shah Deniz in Azerbaijan to the Turkish border was ready for operation in November 2006. BP is the operator and holds a 25.5% interest.
- ☐ Through the LukArco joint venture, BP holds a 5.75% interest (with a 25% funding obligation) in the Caspian Pipeline Consortium (CPC) pipeline. CPC is a 1,510-kilometre pipeline from Kazakhstan to the Russian port of Novorossiysk and carries crude oil from the Tengiz field (BP 2.3%). In addition to our interest in LukArco, we hold a separate 0.87% interest (3.5% funding obligation) in CPC through a 49% holding in Kazakhstan Pipeline Ventures. In 2006, CPC total throughput reached 31.2 million tonnes. During 2006, negotiations continued between the CPC shareholders towards the approval of an expansion plan. The expansion would require the construction of 10

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* □ *Liquefied natural gas on page 32*). BP's Exploration and Production segment has interests in four major LNG plants: the Atlantic LNG plant in Trinidad (BP 34% in Train 1, 42.5% in each of Trains 2 and 3 and 37.8% in Train 4); in Indonesia, through our interests in the Sanga-Sanga PSA (BP 38%), which supplies natural gas to the Bontang LNG plant, and Tangguh (PSA, BP 37.2%), which is under construction; and in Australia through our share of LNG from the NWS natural gas development (BP 16.7% infrastructure and oil reserves/15.8% gas and condensate reserves).

Assets and activities:

- We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2006 supplied 5.6 million tonnes (290bcf) of LNG, up 3.6% on 2005.
- 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. Construction continued during 2006 on 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. The train is expected to be commissioned during the second half of 2008. NWS produced 12.0 million tonnes (544bcf) of LNG, an increase of 2% on 2005.
- In Indonesia, BP is involved in two of the three LNG centres in the country. BP participates in Indonesia's LNG exports through its holdings in the Sanga-Sanga PSA (BP 38%). Sanga-Sanga currently delivers around 15.5% of the total gas feed to Bontang, one of the world's largest LNG plants. The Bontang plant produced 19.5 million tonnes (886bcf) of LNG in 2006, compared with 19.4 million tonnes in 2005.
- Also in Indonesia, BP has interests in the Tangguh LNG joint venture (BP 37.2% and operator) and in each of the Wiriagar (BP 38% and operator), Berau (BP 48% and operator) and Muturi (BP 1%) PSAs in north-west Papua that are expected to supply feed gas to the Tangguh LNG plant. During 2006, construction continued on two trains, 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 (388bcf) a year. 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 (253bcf) a year 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 US, Dominican Republic and other destinations. BP's net share of the capacity of Atlantic LNG Trains 1, 2, 3 and 4 is 6.5 million tonnes (305bcf) of LNG a year.

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Refining and Marketing

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

Key statistics

	\$ million		
	2006	2005 ^a	2004 ^a
Sales and other operating revenues for continuing operations	232,855	213,326	170,639
Profit before interest and tax from continuing operations	5,541	6,426	6,506
Total assets	80,964	77,485	73,582
Capital expenditure and acquisitions	3,144	2,860	2,989
	\$ per barrel		
Global Indicator Refining Margin ^b	8.39	8.60	6.31

Profit before interest and tax from continuing operations includes profit after interest and tax of equity-accounted entities.

- a With effect from 1 January 2006, the following assets were transferred to or from the Refining and Marketing segment:
- Three equity-accounted entities were transferred from Other businesses and corporate following the sale of Innovene;
 - The South Houston Green Power co-generation facility (in the Texas City refinery) and the Watson co-generation facility (in the Carson refinery) were transferred to Gas, Power and Renewables as a result of the formation of BP Alternative Energy; and
 - Hydrogen for Transport activities were transferred from Gas, Power and Renewables.
- The 2005 and 2004 data above has been restated to reflect these transfers.
- 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.

	\$ million		
	2006	2005	2004
Sale of crude oil through spot and term contracts	38,577	36,992	21,989
Marketing, spot and term sales of refined products	177,995	155,098	124,458
Other sales including non-oil and to			

other segments	16,283	21,236	24,192
	232,855	213,326	170,639
			mb/d
Sale of crude oil through spot and term contracts	2,110	2,464	2,312
Marketing, spot and term sales of refined products	5,801	5,888	6,398

The Refining and Marketing segment includes a portfolio of businesses, namely 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. Over the past five years, this has been taking place through upgrades of existing conversion units at several of our facilities and investment in new clean fuels units at the Castellón refinery in Spain, the Kwinana refinery in Australia and all our US refineries (excluding the Carson refinery, which was already producing a full slate of clean fuels). Over the next five years, our refining

portfolio will be upgraded further through the construction of a new coker at the Castellón refinery, an increase in the Whiting refinery's ability to process Canadian heavy crude, upgrades to diesel and gasoline desulphurization capability at the Nerefco refinery in the Netherlands, completion of a major upgrade to the olefin cracker at the Gelsenkirchen refinery in Germany and the site reconfiguration and installation of a new hydrocracker at the Bayernoil refinery, also in Germany. In addition, the portfolio will be improved through upgrades implemented during the recommissioning of the Texas City refinery in the US.

Our marketing businesses, underpinned by world-class manufacturing such as our Aromatics and Acetyls portfolio, generate customer value by providing quality products and offers. Our retail strategy provides differentiated fuel and convenience offers to some of the most attractive 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 derives from several factors, including location (such as the proximity of manufacturing assets to markets), operating cost and physical asset quality.

We are one of the major refiners of gasoline and hydrocarbon products in the US, Europe and Australia. We have significant retail and business-to-business market positions in the US, UK, Germany and the rest of Europe, Australasia, Africa and Asia. We are enhancing our presence in China and exploring opportunities in India. Refining and Marketing also includes the Aromatics and Acetyls business, which maintains manufacturing positions globally, with an emphasis on Asia growth, particularly in China.

During 2006, significant events were:

- BP announced that it had entered the final planning stage of a \$3-billion investment in Canadian heavy crude oil processing capability at its Whiting, US, refinery. This project is expected to reposition Whiting competitively as a top-tier refinery by increasing its Canadian heavy crude processing capability by 260,000 barrels per day and modernizing it with equipment of significant size and scale. Reconfiguring the refinery also has the potential to increase its production of motor fuels by about 15%, which is about 1.7 million additional gallons of gasoline and diesel per day. Construction is tentatively scheduled to begin in 2007, pending regulatory approval.
- BP also announced plans to invest \$500 million over the next 10 years to establish a dedicated bioscience research laboratory. The BP Energy Biosciences Institute (EBI) is planned to be the first of its kind in the world and to be attached to a major academic centre. On 1 February 2007, BP announced that it had selected the University of California, Berkeley, and its partners the University of Illinois at Urbana-Champaign and the Lawrence Berkeley National Laboratory for the research programme. Further, BP and DuPont announced the creation of a partnership to develop, produce and market a next generation of biofuels. The companies' joint strategy is to deliver advantaged biofuels that will provide improved options for expanding energy supplies and accelerate the move to renewable transportation fuels that lower overall greenhouse gas emissions. The first product to market is expected to be biobutanol, an improved biocomponent for gasoline. Initial introduction activities are currently targeted on the UK market.
- In 2006, plans for a second purified terephthalic acid (PTA) plant at the BP Zhuhai Chemical Company Limited site in Guangdong province, China, were approved by the Chinese government and the plant is expected to

come on stream at the end of 2007.

□ BP continues to develop its retailing business in both new markets and new business models. In 2006, developments included:

- The roll-out of the BP Connect Wild Bean Café brands to its dealer network in a franchise agreement. We are expecting to develop a network of 150 Connect franchise sites along with a further 100 company-owned Connect sites in the UK by the end of 2010.
- The successful piloting of a Marks & Spencer store partnership in the UK, with the intention of rolling this out to a further 200 stores in 2007.

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- In a study by Corporate Research International, US consumers ranked BP's convenience chain in the US as the best for customer service.
- BP completed the disposal of its shareholding in Zhenhai Refining and Chemicals Company to Sinopec, sold its shareholding in Eiffage, the French-based construction company, and completed the disposal of its network of 70 retail sites in the Czech Republic.
- BP also announced its intention to sell the Coryton refinery in the UK, which processes 172,000 barrels of crude oil per day. On 1 February 2007, we announced that the sale of the refinery to Petroplus Holdings AG had been agreed, subject to required regulatory approvals. The sale includes the adjacent bulk terminal and BP's UK bitumen business which is closely integrated with the refinery. Completion of the sale is expected in mid-2007.

Texas city refinery

Summary

Throughout 2006, BP continued to respond to the 23 March 2005 incident at its Texas City refinery. BP addressed a number of the factors that contributed to the incident, including the announcement of a new policy for the siting of occupied portable buildings and the removal from service at Texas City of all blow-down stacks handling heavier-than-air light hydrocarbons. BP also implemented a number of actions relating to safety and operations, not only at US refineries but also at other facilities worldwide. These actions include a decision to increase spending to an average of \$1.7 billion a year over the next four years to improve the integrity and reliability of US refining assets, the formation of a safety and operations function to focus on operations and process safety across the group, the appointment of a new chairman and president of BP America Inc. and the creation of an advisory board to assist BP America Inc.'s management in monitoring and assessing BP's US operations. Also in 2006, BP settled a large number of civil suits arising from the Texas City incident. BP established a \$1.625 billion provision related to the incident and reached settlements with all the relatives of those who were killed and with hundreds of other persons who filed injury claims. Trials have been scheduled for a number of unresolved claims in mid-2007, although to date all claims scheduled for trial have been resolved in advance of trial.

In 2006, BP continued its co-operation with the governmental entities investigating the incident, including the US Department of Justice (DOJ), the US Environmental Protection Agency (EPA), the US Occupational Safety & Health Administration (OSHA), the US Chemical Safety and Hazard Investigation Board (CSB) and the Texas Commission on Environmental Quality (TCEQ). During 2006, BP also devoted significant time and effort to co-operate with the BP US Refineries Independent Safety Review Panel (the panel), which it chartered in 2005 on the recommendation of the CSB, to assess the effectiveness of corporate oversight of safety management systems at BP's US refineries and the corporate safety culture. The panel published its report in January 2007 and BP has committed to implement its recommendations

(see *Report of the BP US Refineries Independent Safety Review Panel* on page 25).

Background

The March 2005 explosion and fire at BP Products North America Inc.'s Texas City refinery occurred in the isomerization unit of the refinery as the unit was starting up after routine planned maintenance. The incident claimed the lives of 15 workers and injured many others.

An internal BP incident investigation determined that the raffinate splitter at the isomerization unit was overfilled and overheated, causing the relief valves to open into the blow-down system and resulting in an overflow of liquid hydrocarbon from the blow-down stack. The resulting vapour cloud was ignited by a source that has not been definitively identified.

BP's incident investigation team found that the critical factors leading to the incident included over-pressurization of the raffinate splitter, resulting in loss of containment, the failure to follow procedures during the start-up, the placement of temporary trailers too close to the blow-down stack and the design and operation of the blow-down stack. The investigation team issued a comprehensive final report, which is available in full on the BP internet site, www.bpreponse.org. The final report identified a number of underlying causes related to the working environment, process safety

and other management and operational behaviours and processes at the Texas City refinery.

The investigation team recommended numerous changes relating to people, procedures, control of work and trailer siting, design and engineering, underlying systems and investigation and reporting of incidents. The Texas City refinery established a programme office to implement the recommendations from this report and to address other projects needed to enhance the safety and performance of the refinery. In addition, in the immediate wake of the incident, a new Texas City site manager was appointed in May 2005. That manager has been succeeded by a permanent replacement, whose tenure at the refinery began in the first quarter of 2007. Steps were taken following the incident to strengthen the leadership team, clarify responsibilities and introduce systems to improve communication and compliance. All occupied trailers have been removed from specified areas, an enhanced training programme is under way and the site has committed to restarting process units without any blow-down

stacks in heavier-than-air light hydrocarbons.

The incident prompted a number of investigations by other state and federal agencies. The TCEQ and OSHA investigations of the incident resulted in settlement agreements between BP and the agencies. In the third quarter of 2005, BP reached a settlement with OSHA that resulted in the payment of a \$21.4 million penalty, an agreement to correct all alleged safety violations and the retention of experts to assess the refinery's organization and process safety systems. In the second quarter of 2006, BP settled with the TCEQ, resolving 27 alleged violations by paying a \$0.3 million fine and agreeing, among other things, to upgrade its flare system.

In August 2005, the CSB issued an urgent recommendation to BP to establish an independent panel to assess and make recommendations regarding BP's corporate oversight of safety management systems at its five US refineries and its corporate safety culture. BP established the panel in October 2005, chaired by former US Secretary of State James A Baker, III, and co-operated fully with the panel. In order to make a thorough and credible assessment, the panel visited all BP's US refineries, commissioned independent process safety audits, interviewed staff at all levels, including operators and refinery managers and leadership teams, conducted an extensive process safety cultural survey and reviewed tens of thousands of documents.

BP expects the CSB to issue its final report in March 2007, supplementing two interim reports of findings. At a news conference on 31 October 2006, the CSB issued an update on the status of its own 20-month investigation into the causes of the incident and also issued recommendations to the American Petroleum Institute (API) to amend its guidance relating to atmospheric relief systems and to OSHA to establish a national emphasis programme promoting the elimination of unsafe systems in favour of safer alternatives.

The DOJ is investigating whether the Texas City incident involved any criminal conduct. The DOJ has issued Grand Jury subpoenas for documents and testimony. The investigation, with which BP is co-operating, is ongoing.

The refinery was entirely shut down in September 2005 in anticipation of Hurricane Rita. The hurricane caused the loss of steam and power to the refinery and these services were not fully restored until December 2005. The site-wide shut-down of the Texas City refinery also affected the Aromatics and Acetyls business, which has a co-located manufacturing capacity of paraxylene (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 has been restarted in line with the ongoing phased recommissioning of the refining units.

Throughout the period from September 2005 to the end of the first quarter of 2006, BP worked to understand the extent of the damage the hurricane and loss of power had caused and put into place detailed plans to effect repair and safe restart of the process units. This was a considerable task, involving the entire workforce at the site plus significant external engineering resources.

At the end of the first quarter of 2006, the refinery restarted production and reached an average throughput of 248,000 barrels per day in the fourth quarter of 2006. The site started up smoothly and

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safely and is producing gasoline, diesel and chemicals products for the US market.

In parallel, refinery personnel have continued to work to effect the repair and the safe restart of the remaining process units. Additional processing facilities were commissioned in the second and third quarters of 2006. Additional conversion capacity is expected to be brought online in 2007. BP's plan is to bring additional sour crude processing facilities back on-stream in the second half of 2007; these facilities will allow the processing of additional high-sulphur crude. We expect crude throughputs to be approximately 400,000 barrels per day by the end of 2007.

The following milestones have been achieved in returning the refinery to operation with sequenced reconditioning of a multitude of units:

- Major site commissioning involving more than 15 million worker hours to date.
- Refurbishment and safe start-up of 27-mile steam system.
- Extensive mechanical renovation and the installation of a new flare system.
- Creation of a new command centre with interactive audio/visual links to the units, manned 24 hours a day during unit start-up.
- Implementation of a holistic commissioning plan defining behaviours and accountabilities to deliver safe and successful start-up.
- Implementation of a comprehensive systems training programme, coupled with safety accountability roll-out plans.

Several other improvements are either complete or under way:

- A new office building for more than 400 Texas City workers was opened to relocate workers who can work outside our plant fence line.
- A new flue gas scrubber is being added to the FCC unit. This \$80-million investment will reduce emissions of sulphur and nitrogen oxide from the refinery.
- A new Employee Services Building (ESB) is under construction. The ESB will include facilities for learning and development and operations training departments, including unit training simulators and nine training rooms, the medical department, some of the site's security team, the Incident Management Team and site union official offices.

Construction has started on a new 250 megawatt (MW) steam turbine power generating plant that will reduce emissions and improve both energy and operational efficiency. The \$100-million unit will be located next to the existing South Houston Green Power LP co-generation facility and is expected to boost the total electricity generating capacity located at the Texas City refinery site to 1,000MW.

Report of the BP US Refineries Independent Safety Review Panel

On 16 January 2007, having completed its review, the panel issued its report. The report identified deficiencies in process safety performance at BP's US refineries and called on BP to give process safety the same priority that it had historically given to personal safety and environmental performance. In making its findings and recommendations, the panel stated its objective was excellence in process safety performance, not simply legal compliance. The panel specifically noted that, "during the

course of its review, it saw no information to suggest that anyone – from BP's board members to its hourly workers – acted in anything other than good faith."

The panel made 10 recommendations relating to: process safety leadership; integrated and comprehensive process safety management system; process safety knowledge and expertise; process safety culture; clearly defined expectations and accountability for process safety; support for line management; leading and lagging performance indicators for process safety; process safety auditing; board monitoring; and industry leader. The panel's report in its entirety can be found at www.bp.com/bakerpanelreport.

The panel acknowledged the measures BP had taken since the Texas City incident, including dedicating significant resources and personnel intended to improve the process safety performance at BP's US refineries. BP has committed to implement the panel's recommendations and will consult with the panel on how best to do this across the US refineries and to apply the lessons learned elsewhere in its global operations.

Other refinery investigations

As a result of its investigation of the Texas City refinery, OSHA conducted an inspection of BP Products North America Inc.'s Toledo refinery, beginning in October 2005. On 24 April 2006, OSHA issued citations with a total penalty of \$2.4 million, alleging 39 separate violations of two different OSHA standards. BP and OSHA have reached a settlement in principle and are working towards finalizing the documentation.

On 15 November 2006, the Indiana Occupational Safety and Health Administration (IOSHA) issued the Whiting

refinery with three Safety Orders and Notifications of Penalty alleging 14 separate violations of the OSHA regulations. The total proposed penalty was \$0.4 million. On 7 December 2006, BP and IOSHA met to discuss resolution of the matter. Discussions to reach a settlement agreement are ongoing.

Refining

The company's global refining strategy is to own and 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 its 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 its location, scale and configuration to produce fuels from low-cost feedstocks in line with the demand of the region. 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 and improving our competitive position and developing the capability to produce the cleaner fuels that meet the requirements of our customers and their communities.

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The following table summarizes the BP group's interests in refineries and crude distillation capacities at 31 December 2006.

		mb/d		
		Crude distillation capacities ^a		
	Refinery	Group interest ^b %	Total	BP share
UK	Coryton* ^c	100.0%	172	172
Total UK			172	172
Rest of Europe				
Germany ^d	Bayernoil	22.5%	272	61
	Gelsenkirchen*	50.0%	268	134
	Karlsruhe	12.0%	302	36
	Lingen*	100.0%	91	91
	Schwedt	18.8%	226	42
Netherlands	Nerefco*	69.0%	400	276
Spain	Castellón*	100.0%	110	110
Total Rest of Europe			1,669	750
USA				
California	Carson*	100.0%	265	265
Washington	Cherry Point*	100.0%	232	232
Indiana	Whiting*	100.0%	405	405
Ohio	Toledo*	100.0%	155	155
Texas	Texas City*	100.0%	475	475
Total USA			1,532	1,532
Rest of World				
Australia	Bulwer*	100.0%	101	101
	Kwinana*	100.0%	137	137
New Zealand	Whangarei	23.7%	101	24
Kenya	Mombasa	17.1%	94	16
South Africa	Durban	50.0%	182	91
Total Rest of World			615	369
Total			3,988	2,823

* Indicates refineries operated by BP.

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

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

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c BP has announced the sale of its Coryton refinery, subject to required regulatory approvals.

d BP's share of the Reichstett refinery in Germany was sold in December 2006.

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 is summarized.

	thousand barrels per day		
Refinery throughputs ^a	2006	2005	2004
UK	165	180	208
Rest of Europe	648	667	684
USA	1,110	1,255	1,373
Rest of World	275	297	342
Total	2,198	2,399	2,607
Refinery capacity utilization			
Crude distillation capacity at 31 December ^b	2,823	2,832	2,823
Crude distillation capacity utilization ^c	76%	87%	93%
USA	70%	82%	95%
Europe	87%	90%	90%
Rest of World	78%	88%	87%

a Refinery throughputs reflect 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 2006 refinery throughput declined as a result of increased turnaround activity during the year. In the US, the year-on-year decline was as a result of the full shutdown of the Texas City refinery in September 2005 and the subsequent maintenance programme that led to a partial and phased start-up during 2006.

[Back to 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, including 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.

	thousand barrels per day		
Sales of refined products ^a	2006	2005	2004
Marketing sales			
UK ^b	356	355	322
Rest of Europe	1,340	1,354	1,360
USA	1,595	1,634	1,682
Rest of World	581	599	638
Total marketing sales ^c	3,872	3,942	4,002
Trading/supply sales ^d	1,929	1,946	2,396
Total refined products	5,801	5,888	6,398

\$ million

Proceeds from sale of refined products	177,995	155,098	124,458
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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 and 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.

	thousand barrels per day		
Marketing sales by refined product	2006	2005	2004
Aviation fuel	488	499	494
Gasolines	1,603	1,603	1,675
Middle distillates	1,170	1,185	1,255
Fuel oil	388	379	343
Other products	223	276	235
Total marketing sales	3,872	3,942	4,002

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 upgrading our transactional and operational processes, 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 3,872mb/d in 2006, compared with 3,942mb/d in the previous year. The decrease was due mainly to the effects of the high price environment in certain retail markets and of BP

reducing volumes in less profitable business-to-business markets.

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 acid. 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 optimization.

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, while 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 US, the am/pm offer west of the Rocky Mountains in the US or the Aral offer in Germany.

Each of these brands carries a very strong offer and we also aim to share best practices between them. Since 2003, we upgraded our fuel offer with the introduction of Ultimate gasoline and diesel products. In 2006, we launched Ultimate in South Africa and Russia and now market Ultimate in 15 countries.

We continue to focus on operational efficiencies through targeted portfolio upgrades to drive increases in our fuel throughput per site and our store sales per square metre. In 2006, across the network, same-store sales growth at 4% exceeded estimated market growth of 2%.

	\$ million		
Store sales ^a	2006	2005	2004
UK	647	628	655
Rest of Europe	2,821	3,069	3,090
USA	1,755	1,776	1,715
Rest of World	591	610	601
Total	5,814	6,083	6,061
Direct-managed	2,528	2,489	2,319
Franchise	3,286	3,533	3,623
Store alliances	□	61	119
Total	5,814	6,083	6,061

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. Not all retail sites include a BP convenience store.

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

	Number of retail sites		
Retail sites ^a	2006	2005	2004
UK	1,300	1,300	1,300
Rest of Europe	7,700	7,900	8,000
USA (excluding jobbers)	2,700	3,100	3,900
USA jobbers	9,600	9,700	10,300
Rest of World	3,300	3,200	3,300
Total	24,600	25,200	26,800

a Retail sites includes all sites operated under a BP brand.

At 31 December 2006, BP's worldwide network consisted of more than 24,000 locations branded BP, Amoco, ARCO and Aral, compared with approximately 25,000 in the previous year. We continue to improve the efficiency of our retail asset network and increase the consistency of our site offer through a process of regular review. In 2006, we sold 513 company-owned sites to dealers and jobbers who continue to operate these sites under the BP brand. We also divested an additional 301 company-owned sites (including all company-owned sites in the Czech Republic) to third parties.

In 2006, we continued the rollout of the BP Connect offer at sites in the UK and US, 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 cleaner fuels. The BP Connect sites include both those that are new and those where extensive upgrading and remodelling have taken place. At 31 December 2006, more than 760 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 31 December 2006, BP's retail network in the US comprised approximately 12,300 sites, of which approximately 9,600 were owned by jobbers. BP's network comprised about 9,000 sites in the UK and the Rest of Europe and 3,300 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, 387 sites were operational at 31 December 2006. The joint venture 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

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operations with 151 sites in Ningbo in 2005, with a further 72 sites in Shaoxing being transferred into the joint venture in 2006. The joint venture plans to build, operate and manage a network of 500 sites in Hangzhou, Ningbo and Shaoxing within Zhejiang province.

Lubricants

We manufacture and market lubricants 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, and 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 cornerstones of our long-term strategy. BP markets through its two major brands, Castrol and BP, and several secondary brands, including Duckhams, Veedol and Aral.

In the consumer sector of the automotive segment, we supply lubricants, other products and related business services to intermediate customers such as retailers and 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 such as Russia, China, India, the 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 Marketing markets a comprehensive range of refinery and lubricants products focused on business customers in the aviation fuel, marine fuel, marine and industrial lubricants, LPG and the ground fuels sectors.

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 26,854 million litres (approximately 463 thousand barrels per day) and has relationships with many of the major commercial airlines. Air BP's strategic aim is to strengthen its position in existing markets (Europe/US/Asia Pacific), while creating opportunities in 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 14 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 is

one of the leading importers of LPG into the Chinese market, where we continued to grow our retail LPG business. LPG Marketing Product sales in 2006 were approximately 71 thousand barrels per 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 presence in the marine fuels sector. The business has offices in 90 countries and operates in more than 1,150 ports.

The Commercial Fuels business has activities in approximately 14 European countries and marketing sales of approximately 596 thousand barrels per day. The business markets fuels and heating oil, mostly as pick-up business at refineries, terminals and depots.

Our Business Marketing activities also include Industrial Lubricants, selling industrial lubricants and services to manufacturing companies in approximately 40 countries, and the supply of bitumen to the road and roofing industries. The businesses seek to increase value by building from the technology, marketing and sales capabilities of a business to business operation.

BP supports its businesses through a dedicated Strategic Accounts organization. Strategic Accounts develops strategic relationships with carefully selected leading organizations in targeted markets, where mutual strategic and financial value can be created. Its operating model manages each relationship in a disciplined manner to achieve growth and efficiency for BP and its partners through focused offer development and capability building. Relationships are held across organizations and involve many senior leaders in the partners' organizations.

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 intermediate 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 Dimethyl 2, 6 Naphthalene dicarboxylate (NDC),

which is used for optical film and specialized packaging, and acetic anhydride, ethyl acetate and vinyl acetate monomer (VAM), which are used in cellulose acetate, paints, adhesives and solvents.

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 are also investing in maintaining and developing our technology leadership position to deliver both operating and capital cost advantages.

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The following table shows BP's Aromatics and Acetyls production capacity at 31 December 2006. This production capacity is based on the original design capacity of the plants plus expansions.

					thousand tonnes per year
Geographic area	PTA	PX	Acetic acid	Other	Total BP share of capacity
UK					
Hull			529	633	1,162
Rest of Europe					
Belgium					
Geel	1,076	552			1,628
USA					
Cooper River	1,309				1,309
Decatur	1,043	1,145		29	2,217
Texas City		1,309	543 ^a	123	1,975
Rest of World					
China					
Chongqing			202 ^b	52	254 (51% of YARACO) ^b
Zhuhai	582				582
Indonesia					
Merak	252				252 (50% of PT Ami)
Korea					
Ulsan	553 ^c		242 ^d	57 ^e	852 (47% of SPC) ^c (34% of ASACCO) ^e
Seosan	353 ^c				353 (51% of SS-BP) ^d (47% of SPC) ^c
Malaysia					
Kertih			545		545
Kuantan	699				699
Taiwan					
Kaohsiung	822 ^f				822 (61% of CAPCO) ^f
Taichung	457 ^f				457 (61% of CAPCO) ^f
Mai Liao			153 ^g		153 (50% of FBPC) ^g
	7,146	3,006	2,214	894	13,260

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

^b Yangtze River Acetyls Company.

^c Samsung-Petrochemicals Company Ltd.

^d Samsung-BP Chemicals Ltd.

^e Asian Acetyls Company Ltd.

^f China American Petrochemical Company Ltd.

^g Formosa BP Chemicals Corporation.

In addition to the plans for a second PTA plant at the BP Zhuhai 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:

In the third quarter of 2006, BP announced its intent to sell its 47.41% equity interest in Samsung Petrochemical Co. Ltd (SPC), a PTA joint venture with Samsung in South Korea.

In 2004, BP announced the phased closure of two acetic acid plants at Hull, UK. The first plant was shut down in the second quarter of 2005 and the remaining plant was shut down in the third quarter of 2006.

The development of a 350 thousand tonnes per annum (ktepa) PTA expansion at Geel, Belgium, is expected to be operational in early 2008 and to increase the site's PTA capacity to 1,426ktepa.

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 that 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 the Far East. Over-the-counter contracts include a variety of options, forwards and 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 grades. Over-the-counter crude forward sales contracts are used by BP to buy and sell the underlying physical commodity, as well as to act 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, which are described further below. The volume of activity in 2006 was similar 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 improve selections of crude for refineries further. 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 maximize the value of the whole supply chain through the optimization of storage and pipeline

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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:

□ Exchange-traded commodity derivatives

These contracts are typically in the form of futures and options traded on a recognized exchange, such as Nymex, Simex, ICE 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 accounting purposes.

□ Over-the-counter (OTC) contracts

These contracts are typically in the form of forwards, swaps and options. OTC contracts are negotiated between two parties and 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 accounting purposes.

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 that 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 and 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.

□ 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 when title to the inventory is taken. 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. 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 accounting purposes, 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 accounting purposes.

Trading investigations

See Legal proceedings on page 77 for further details regarding investigations into various aspects of BP's trading activities.

The independent review, commissioned by BP, of the current compliance approach in the group's US trading organization has been completed. A number of recommendations have been made in regard to the design and effectiveness of the compliance processes and procedures. BP is fully implementing these recommendations.

Transportation

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

Shipping

We transport our products across oceans, around coastlines and along waterways, using a combination of BP-operated time-chartered and spot-chartered vessels. All vessels on BP business are subject to our health, safety, security and environmental requirements. In 2006, we continued to expand our operated and time-chartered fleet in order to provide more protection against the risk of a major oil spill. This fleet transformation is ahead of the international requirements for phase-out of single-hulled vessels.

International fleet

In 2005 we managed an international fleet of 52 vessels (44 oil tankers and eight LNG carriers). At the end of 2006, we had 57 international vessels (42 medium-size crude and product carriers, four very large crude carriers, one North Sea shuttle tanker, seven LNG carriers and three new LPG carriers). All these ships are double-hulled.

Of the seven LNG carriers, BP manages four on behalf of joint ventures in which it is a participant and operates three LNG carriers, with a further four on order for delivery in 2007 and 2008.

Regional and specialist vessels

In Alaska, we took delivery of the fourth and final ship in a series of new-build double-hulled tankers and redelivered one of our time-chartered vessels back to the owner. The entire Alaskan fleet of six vessels is double-hulled.

In the Lower 48, two of the four heritage Amoco barges remain in service, one of which is due to be phased out of BP's service in 2007. We now intend to retain the other, which is double-hulled, until 2009.

Outside the US, the specialist fleet has grown from six ships in 2005 to 16 in 2006 (three tugs, two double-hulled lubricants oil barges and 11 offshore support vessels).

Time charter vessels

BP has 100 hydrocarbon-carrying vessels above 600 deadweight tonnes on time charter, of which 83 are double-hulled and three are double-bottomed. All these vessels are enrolled in BP's Time Charter Assurance Programme.

Spot charter vessels

To transport the remainder of the group's products, BP spot charters vessels, typically for single voyages. These vessels are always vetted prior to use.

Other vessels

BP uses miscellaneous craft such as tugs, crew boats and seismic vessels in support of the group's business. We also use sub 600 deadweight tonne barges to carry hydrocarbons on inland waterways.

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Gas, Power and Renewables

The Gas, Power and Renewables segment includes four main activities: marketing and trading of gas and power; marketing of liquefied natural gas (LNG); natural gas liquids (NGLs); and low-carbon power generation through our Alternative Energy business.

The strategic purpose of the segment comprises four elements:

- Develop a leading low-carbon power generation business across the value chain.
- Access cost competitive supply.
- Capture distinctive world-scale gas market positions by accessing key pieces of infrastructure.
- Expand gross margin by providing distinctive energy products and services to selected customer segments and by optimizing the gas and power value chains.

Key statistics

\$ million

	2006	2005 ^a	2004 ^a
Sales and other operating revenues from continuing operations	23,708	25,696	23,969
Profit before interest and tax from continuing operations	1,321	1,172	1,003
Total assets	27,398	28,952	17,753
Capital expenditure and acquisitions	688	235	530

Profit before interest and tax from continuing operations includes profit after tax of equity-accounted entities.

a On 1 January 2006, following the formation of the Alternative Energy business, certain mid-stream assets and activities were transferred into Gas, Power and Renewables and the 2005 and 2004 data above has been restated to reflect these transfers:

- South Houston Green Power co-generation facility (in the Texas City refinery) from Refining and Marketing.
- Watson co-generation facility (in the Carson refinery) from Refining and Marketing.
- Phu My Phase 3 combined cycle gas turbine (CCGT) plant in Vietnam from Exploration and Production.

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

\$ million

	2006	2005	2004
Gas marketing sales	11,428	15,222	13,532
Other sales (including NGLs marketing)	12,280	10,474	10,437
	23,708	25,696	23,969

mmcf/d

	2006	2005	2004
Gas marketing sales volumes	3,685	5,096	5,244
Natural gas sales by Exploration and Production	5,152	4,747	3,670

We seek to maximize the value of our gas by targeting high-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 UK and the most liquid trading locations in continental Europe. Some long-term natural gas contracting activity is included within the Exploration and Production business segment because of the nature of the gas markets when the long-term sales contracts were agreed.

Our LNG business develops opportunities to capture sales for our upstream natural gas resources, working in close collaboration with the Exploration and Production business. For sales into non-liquid markets such as Japan and Korea, we aim to secure contracts with high-value customers. For the majority of sales into liquid wholesale markets such as the US and UK, we are building integrated supply chains covering production, liquefaction, shipping, regasification and access to the wholesale transmission grid. Our strategy is to capture a growing share of the internationally traded gas market. We are focusing on markets that offer significant prospects for growth. Our LNG activities involve the marketing of third-party LNG as well as BP equity volumes, where this allows us to optimize our existing asset and contractual positions.

Our NGLs business is engaged in the processing, fractionation and marketing of ethane, propane, butanes and pentanes extracted from natural gas. We have a significant NGLs processing and marketing business in North America. Our NGLs activity is underpinned by our upstream resources and serves third-party markets for chemicals and clean fuels as well as supplying BP's refining activities.

Globally, the power sector is the largest source of greenhouse gas (GHG) emissions, which are responsible for about twice the emissions from transport. Creating low-carbon power is therefore critical in the effort to stabilize global GHG emissions. BP is focused on power generation activities with low-carbon emissions. In 2005, 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.

Capital expenditure and acquisitions for 2006 was \$688 million, compared with \$235 million in 2005 and \$530 million in 2004. In 2006, this included the acquisitions of Orion Energy, LLC, and Greenlight Energy, Inc. In 2005 and 2004, there were no acquisitions. Capital expenditure excluding acquisitions for 2007 is planned to be around \$900 million. The increase over the 2006 level primarily reflects our project programme, including continuing investment in the Alternative Energy business.

Marketing and trading activities

Gas and power marketing and trading activity is undertaken primarily in the US, Canada, the UK and continental Europe to market BP's gas and power production and manage market price risk as well as to 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.

The group also has an NGLs trading activity in the US for delivering value across the overall NGLs supply chain, sourcing optimal feedstock to our processing assets and securing access to markets with flexible and competitive supply.

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 marketplace. 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, while 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, while 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 both to sell production into the wholesale markets and as trading instruments to buy and sell gas and power in future periods. 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 contracts that the group enters into is described below in more detail:

□ 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 accounting purposes.

□ Over-the-counter (OTC) contracts

These contracts are typically in the form of forwards, swaps and options. OTC contracts are negotiated between two parties and are not

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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 accounting purposes.

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 dispatch. 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 and 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 natural gas products or power 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.

□ Spot and term contracts

Spot contracts are contracts to purchase or sell a commodity at the market price prevailing on the delivery date when title to the inventory passes. 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. 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. 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 accounting purposes. See Financial and operating performance □ Gas, Power and Renewables on page 46.

Trading investigations

See Legal proceedings on page 77 for details regarding investigations into various aspects of BP's trading activities.

The independent review, commissioned by BP, of the current compliance approach in the group's US trading organization has been completed. A number of recommendations have been made in regard to the design and effectiveness of the compliance processes and procedures. BP is fully implementing these recommendations.

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. Our business has been built on the foundation of our position as the continent's leading producer of gas based on volumes. Our gas activity in the US and Canada has grown as the group increased its scale through both organic growth of operations and the acquisition of smaller marketing and trading companies, increasing reach into additional markets. At the same time, 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 2004-2006 because of a number of factors: (i) increased access to transport rights; (ii) increase in our trading activities; and (iii) growth from the acquisition of small regional marketing businesses. The OTC market for NGLs also developed during this period but the scale of activity was not significant in the context of the group's overall marketing 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 high-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.

Europe

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 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, while other commodity contracts such as futures and options can be used to manage the market risk relating to changes in prices.

As UK gas markets become increasingly connected to continental Europe, it is important that we maintain our understanding of how wider European gas markets work. We therefore trade in continental Europe.

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 that currently places us as one of the leading foreign entrants into the Spanish gas market.

Following Spanish deregulation, our 5% shareholding in Enagas, the Spanish gas transport grid operator, was no longer considered strategic and in November 2006 we divested these shares.

Liquefied natural gas

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

BP Exploration and Production has interests in major existing LNG projects in Trinidad, ADGAS in Abu Dhabi, Bontang in Indonesia and the North West Shelf in Australia. Additional LNG supplies are being pursued through an expansion of the existing LNG facilities at the North West Shelf project in Australia and greenfield developments in Indonesia (Tangguh) and Angola. BP has no proved reserves associated with its interests in LNG projects in Abu Dhabi and Angola.

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 project (BP 37.2%) have been signed with POSCO and K-Power for supply to South Korea and with Semptra for supply to the Mexican and US markets. Together with an earlier agreement to supply LNG to China, these agreements mean that markets for more than 7 million tonnes a year (380bcf) of Tangguh LNG have been secured. In March 2005, Tangguh received key government approvals for the two-train launch and the project consortium is now executing the major construction contracts, with start-up planned in late 2008. During 2006, further progress was made in securing contracts for LNG to be derived from the remaining uncontracted reserves at the North West Shelf project.

In the Atlantic and Mediterranean regions, significant progress has also been made in creating opportunities to supply LNG to North American and European gas markets. The fourth LNG train at Atlantic LNG in Trinidad, with a capacity of 5.2 million tonnes per annum (mtpa) (253bcf), began operations in late 2005. BP is marketing its LNG entitlement directly, utilizing BP-controlled LNG shipping and contractual rights to access import terminal capacity in the liquid markets of the US (Cove Point and Elba Island) and the UK (Isle of Grain). These BP-marketed volumes supplement a 2005 long-term agreement with Egyptian Natural Gas Holding Company (EGAS) of Egypt to purchase 1.45 billion cubic metres per year of LNG from the Spanish Egyptian Gas Company (SEGAS) plant at Damietta, short-term contracts to purchase LNG from Oman and Qatar and periodic "spot" purchases of LNG. We have signed a memorandum of understanding with Brass River LNG in Nigeria to purchase around 2 million tonnes a year of LNG, starting in 2010 for 20 years, which will be supplied to multiple markets in the Atlantic basin.

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In south-east China, the Dapeng LNG import and regasification terminal and Trunkline Project (BP 30%) in Guangdong province received its first commissioning cargo during May 2006 and commenced commercial operations in September. LNG for the terminal is supplied under a long-term contract signed with Australia LNG in October 2002 that involves deliveries from the North West Shelf project (BP 16.7% infrastructure and oil reserves/15.8% gas and condensate reserves).

BP continues to progress options for new terminal development in the US. The proposed 1.2 billion cubic feet per day (bcf/d) Crown Landing terminal is 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 during 2006. BP continues to work with the State agencies in New Jersey to complete State permitting requirements and with the relevant federal, state 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 US 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.

Natural gas liquids

With global demand for NGLs, both as a chemicals feedstock and as a cleaner fuel, forecast to grow in excess of 3% a year, this business is expected to offer potential for further growth. Based on sales volumes, we are one of the leading producers and marketers of NGLs in North America and hold interests for NGL volumes in the UK and Egypt.

NGLs produced in North America 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 petrochemicals plants and refineries, including our own. 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 6.4bcf/d. These facilities, which we own or in which we have an interest, are located in major production areas across North America, including Alberta, Canada, the US Rockies, the San Juan basin and the Gulf of Mexico. We also own or have an interest in fractionation plants (that process the natural gas liquids stream into its separate component products) in Canada and the US, and own or lease storage capacity in Alberta, eastern Canada, and the US Gulf Coast, as well as the US West Coast and mid-continent regions. Our North American NGL processing capacity utilization in 2006 was 75%. In addition, we have entered into a long-term supply contract with Aux Sable Liquid Products to secure additional NGLs to supply our customers in the US Midwest.

BP operates one plant in the UK (capacity 1.2bcf/d) and we are a partner (33.33%) in a gas processing plant in Egypt with 1.1bcf/d of gas processing capacity. We have also secured access to the Abibes LPG terminal in Cremona, northern Italy. During the first quarter of 2006, a memorandum of understanding was signed with EGAS for a feasibility study covering construction of a greenfield NGLs plant in the West Nile Delta, Egypt, that would process gas from future BP equity and third-party production offshore.

Alternative energy

BP Alternative Energy is focused on the power generation sector – the largest single source of emissions from the use of fossil fuels – and aims to extend BP's capabilities in solar, wind, hydrogen and gas-fired power generation to produce low-carbon power. Its activities include the production and marketing of solar panels; development of wind farms; generation of electricity from hydrogen power using sequestration in which carbon is captured and stored; and gas-fired power generation, which typically emits only half as much CO₂ as a conventional coal-fired station. The business brings together the group's existing activities in these technologies with our power marketing and trading capabilities to form a single business.

In 2005, BP Alternative Energy announced its plans to invest up to \$8 billion over 10 years. This investment is expected to be spread in broadly equal proportions between solar, wind, hydrogen and high-efficiency gas-fired power generation.

Solar

BP Solar's main production facilities are located in Frederick, Maryland, US; Madrid, Spain; Sydney, Australia; and Bangalore, India. During 2006, the expansion of our manufacturing facilities in India and Spain doubled our production capacity from 100MW in 2004 to 200MW, keeping us on track to triple capacity from 2005 levels by 2008. During 2007, expansion of cell capacity will continue at our Madrid and Bangalore facilities, alongside a \$70-million project to expand casting capacity at Frederick. BP Solar achieved sales of 93MW (2005 105MW and 2004 99MW).

We made good use of technology to manage the current silicon supply issue last year: developing a new silicon

growth process named Mono2, which significantly increases cell efficiency over traditional multi-crystalline-based solar cells. Solar cells made with these wafers, in combination with other BP Solar advances in cell process technology, are expected to be able to produce between 5% and 8% more power than solar cells made with conventional processes. We also teamed up with the California Institute of Technology to launch a multi-million dollar research programme to explore a radically new way of producing solar cells, based on the growth of silicon on "nanorods", which could improve efficiency and make solar electricity much more competitive. In Germany, we signed a co-operation agreement with the Institute of Crystal Growth (IKZ) to develop a process for depositing silicon on glass that has the potential to reduce the amount of silicon feedstock used in cell production. In Spain, BP Solar and Banco Santander have formed an alliance that will allow for the construction of up to 278 photovoltaic solar power installations in Spain, with total capacity of 18-25 megawatts peak.

Wind

We are building expertise in wind energy and implementing projects. We operate two wind farms in the Netherlands, 9MW at our oil terminal in Amsterdam and 22.5MW at the Nerefco oil refinery (both the refinery and wind farm are jointly owned with Chevron (BP 69%)), providing electricity to the local grid.

In the US, we entered into a long-term supply agreement with Clipper Windpower plc with options to purchase Clipper turbines, with a total capacity of 2,250MW. During 2007, we plan to begin construction of five wind power generation projects, located in four states - California, Colorado, North Dakota and Texas. The projects are expected to deliver a combined generation capacity of some 550MW.

During 2006, BP Alternative Energy also acquired Orion Energy, LLC, and Greenlight Energy, Inc. With the acquisition of these large-scale wind energy developers, our North American wind portfolio includes opportunities to develop almost 100 projects with potential total generating capacity of some 15,000MW.

Gas-fired power

Gas-fired power stations typically emit around half as much CO₂ as conventional coal-fired plants.

We operate a 776MW gas-fired power generation facility and an associated LNG regasification facility at Bilbao, Spain (BP 25% share in each) and a 750MW co-generation plant at Texas City, US (50:50 joint venture with Cinergy Solutions, Inc.), which 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. Also, a 50MW co-generation plant near Southampton, UK (BP 100%), has been in operation since the first half of 2005. The construction of K-Power's (BP 35%) 1,074MW gas-fired combined cycle power plant at Kwangyang, Korea, was completed and full commercial operations started in the second quarter of 2006.

We have started construction of a new 250MW steam turbine power generating plant at the Texas City refinery site, which is expected to bring the total capacity of the site to 1,000MW when completed in 2008. We also plan to construct a 520MW co-generation facility at Cherry Point, Washington, US.

Hydrogen power

During 2006, we announced a new strategic relationship with General Electric to accelerate the development of hydrogen power technology and the deployment of the concept. Progress on our proposed hydrogen plant at Carson, California, US, continued and we were awarded \$90 million in US Federal Investment credits.

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Other businesses and corporate

Other businesses and corporate comprises Finance, the group's aluminium asset, its investments in PetroChina and Sinopec (both divested in early 2004), interest income and costs relating to corporate activities worldwide. Following the sale of Innovene to INEOS in 2005, 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 were transferred to Refining and Marketing, effective 1 January 2006. The 2005 and 2004 data below has been restated to reflect these transfers.

Key statistics

\$ million

	2006	2005	2004
Sales and other operating revenues for continuing operations	1,009	668	546
Profit (loss) before interest and tax from continuing operations ^a	(885)	(1,237)	155
Total assets	14,184	12,144	21,795
Capital expenditure and acquisitions	281	817	2,130

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

Finance

Finance co-ordinates the management of the group's major financial assets and liabilities. From locations in the UK, the US 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, US. Production facilities are located in Logan County, Kentucky, and are jointly owned with Novelis. The primary activity of our aluminium business is the supply of aluminium coil to the beverage can business.

Research, technology and engineering

Research, technology and engineering activities are carried out by each of the major business segments on the basis of a distributed programme co-ordinated by a technology co-ordination 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 forms the Technology Advisory Council, which advises senior management on the state of technology within the group and helps to 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 2006 was \$395 million, compared with \$502 million in 2005 and \$439 million in 2004.

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.

Technology

The realization of technological advancements is pivotal to our strategic progress and business performance. It is also the key to finding and developing solutions that meet the energy and climate challenges of the 21st century.

The sheer range and complexity of technologies that can affect our businesses and the wide variety of sources for these technologies — proprietary, energy service sector, universities and research institutions and other industries — mean that no single approach can meet all our needs.

The following guiding principles underpin our approach to technology:

- Deliver technology leadership in a select few areas of distinctiveness.
- Develop innovative and sustainable technology-based solutions for corporate renewal.
- Drive rapid take-up of proprietary and commercially available technologies.
- Innovate and test technology at material scale.
- Develop and access world-class skills and collaborate internally and externally.

These principles are reflected in how we define technology investment. Whereas research and development is an externally reported number, internally we use a broader but very specific definition for technology investment. This consists of four elements: technology development for incremental improvement of our base businesses; technology leadership areas to create and sustain material, advantaged business positions; long-term technology investments to secure our future; and application and propagation of technology through formalized technology networks and knowledge management processes.

Our five-year technology plan provides for sustained investment in our core technologies and increasing investment in long-term technologies. As we have deepened our current areas of leadership, extended their application in the field and broadened our long-term technology portfolio, our technology investment has grown at an average of 15% a year between 2003 and 2006. In 2006, total technology investment was around \$890 million.

During 2006, we continued to advance and employ new technologies in drilling and well construction, unconventional gas development, enhanced oil recovery and seismic imaging. These technologies have enabled discoveries in the deepwater Gulf of Mexico and Angola, increased production from tight gas fields in the continental US and increased recoveries from our fields in maturing basins, such as Alaska and the North Sea.

Technology advancements are also broadening our refining capability to understand and process ever-lower quality crudes and optimize our assets in real time, enhancing the flexibility and reliability of our refineries. Our proprietary technologies in PTA have continued to reduce manufacturing costs and environmental impact.

Our long-term technology priorities fit into three categories of activity: technologies that enhance our capability to identify new hydrocarbon resources and better exploit those we have; technologies that convert hydrocarbon feedstocks into efficient fuels and chemicals; and selected low-carbon technologies for power and transport to minimize CO₂ emissions.

During 2006, we announced plans to establish a dedicated biosciences energy research laboratory and invest \$500 million over the next 10 years. On 1 February 2007, BP announced that it had selected the University of California, Berkeley, and its partners the University of Illinois at Urbana-Champaign and the Lawrence Berkeley National Laboratory, for the research programme. The Energy Biosciences Institute's aim will be to explore the application of bioscience and the production of new and cleaner energy, initially focusing on renewable biofuels for road transport. It will also pursue bioscience-based research in three other key areas: the conversion of heavy hydrocarbons to clean fuels; improved recovery from existing oil and gas reservoirs; and carbon sequestration.

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Regulation of the group's business

BP's exploration and production activities are conducted in many different countries and are therefore subject to a broad range of legislation and regulations. These cover virtually all aspects of exploration and production activities, including matters such as licence acquisition, production rates, royalties, pricing, environmental protection, export, taxes and foreign exchange. The terms and conditions of the leases, licences and contract 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 with governmental or state entities usually take the form of licences or production-sharing agreements. Arrangements with private property owners are usually in the form of leases.

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. Less typically, BP may explore for and exploit hydrocarbons under a service agreement with the host entity in exchange for reimbursement of costs and/or a fee paid in cash rather than production.

Production-sharing agreements entered into with a government entity or state company generally require 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 US, which typically 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.

Frequently, BP conducts its exploration and production activities in joint venture with other international oil companies, state companies or private companies.

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 on 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 & Tobago.

BP's other activities, including its interests in pipelines and its commodities and trading 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 on this page.

For certain information regarding environmental proceedings, see Environmental protection – US regional review on page 37.

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. See Financial statements – Note 40 on page 143 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. Nineteen 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 in aggregate, expected to be material to the group's results of operations or financial position.

On 23 March 2005, an explosion and fire occurred in the isomerization unit of BP Products North America Inc.'s Texas City refinery as the unit was coming out of planned maintenance. Fifteen workers died in the incident and many others were injured. In 2005 and 2006, BP agreed settlements in respect of all the fatalities and many of the personal injury claims arising from the incident. Trials have been scheduled for a number of unresolved claims in mid-2007, although to date all claims scheduled for trial have been resolved in advance of trial. In 2006, BP continued its co-operation with the governmental entities investigating the incident, including the US Department of Justice (DOJ), the US Environmental Protection Agency (EPA), the US Occupational Safety & Health Administration (OSHA), the US Chemical Safety and Hazard Investigation Board (CSB) and the Texas Commission on Environmental Quality (TCEQ). During 2006, BP also devoted significant time and effort to co-operate with the BP US Refineries Independent Safety Review Panel (the panel), which it chartered in 2005 on the recommendation of the CSB to assess the effectiveness of corporate oversight of safety management systems at BP's US refineries and the corporate safety culture. The panel published its report in January 2007 and BP has publicly committed to implement its recommendations (see *Report of the BP US Refineries Independent Safety Review Panel on page 25*).

The incident prompted a number of investigations by other state and federal agencies. The TCEQ and OSHA investigations of the incident resulted in settlement agreements between BP and the agencies. In the third quarter of 2005, BP reached a settlement with OSHA that resulted in the payment of a \$21.4 million penalty, an agreement to correct all

alleged safety violations and the retention of experts to assess the refinery's organization and process safety systems. In the second quarter of 2006, BP settled with the TCEQ, resolving 27 alleged violations by paying

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a \$0.3 million fine and agreeing, among other things, to upgrade its flare system.

The CSB report is expected to be issued in March 2007.

As a result of its investigation of the Texas City refinery, OSHA conducted an inspection of BP Products North America Inc.'s Toledo refinery beginning in October 2005. On 24 April 2006, OSHA issued citations with a total penalty of \$2.4 million, alleging 39 separate violations of two different OSHA standards. BP and OSHA have reached a settlement in principle and are working towards finalizing the documentation.

On 15 November 2006, the Indiana Occupational Safety and Health Administration (IOSHA) issued the Whiting refinery with three Safety Orders and Notifications of Penalty alleging 14 separate violations of the OSHA regulations. The total proposed penalty was \$0.4 million. On 7 December 2006, BP and IOSHA met to discuss resolution of the matter. Discussions to reach a settlement agreement are ongoing.

On 2 March 2006, a crude oil spill of approximately 4,800 barrels occurred on a low-pressure transit line on the Alaskan North Slope in the Western Operating Area of the 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 affected approximately two acres of frozen tundra. Clean-up and rehabilitation of the area are complete and environmental damage to the tundra is expected to be minimal. On 15 March 2006, the US Department of Transportation (DOT) issued a Corrective Action Order (CAO) that required, among other items, that BP develop a plan to run maintenance pipeline inspection tools (pigs) and smart pigs through the three Prudhoe Bay oil transit lines. The DOT has since issued two amendments to the CAO. Combined, the three orders have required 34 corrective actions. On 6 August 2006, BP Exploration Alaska ordered a phased shutdown of the Prudhoe Bay oil field following the discovery of unexpectedly severe corrosion and a spill of 199 barrels from the oil transit line in the Eastern Operating Area of Prudhoe Bay. The decision was based on the receipt of data from a smart pig run and follow-up inspections where corrosion-related wall thinning appeared to exceed BP criteria for continued operation. It was during these follow-up inspections that BP personnel discovered a leak and a small spill to the tundra. The spill was contained and clean-up began. US and State of Alaska investigations of the incident have been initiated and subpoenas have been issued, including a Federal Grand Jury subpoena. BP continues its discussions with the DOT to assure compliance with the corrective actions outlined in the CADs. In September 2006, BP executives testified before the US House of Representatives and the US Senate.

Management cannot predict future developments, such as increasingly strict requirements of environmental laws and resulting enforcement policies, 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 expenditure see Environmental expenditure on page 47.

BP operates in more than 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 environmental (HSE) 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 HSE regulations and obligations.

This Environmental protection section focuses primarily on the US and the EU, where approximately 70% 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 2008-2012. In 2005, the Kyoto protocol came into force, committing the 156 participating countries to emissions targets and the EU Emissions Trading Scheme (ETS) came into operation. However, Kyoto was only designed as a first step and policymakers continue to discuss what new agreement might follow it in 2012 and how all significant countries can be involved. This was discussed further by the G8 group of world leaders at their St Petersburg summit in 2006 and at the UNFCCC conference in Nairobi, where progress was made on climate impacts adaptation and vulnerability and there was agreement to review the Kyoto protocol by 2008.

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.

In July 2003, final agreement was reached on a European Directive establishing a scheme for GHG emission allowance trading within the EU and, in January 2005, the scheme came into force, capping the CO₂ emissions of major industrial emitters. BP was well prepared for the EU ETS, building on experiences from our own internal emissions trading system (operated between 1999 and 2001) and participation in the UK's own pilot ETS. The EU ETS launched in 2005 covers all BP installations with combustion facilities greater than 20MW thermal input. The first phase of EU ETS will come to completion at the end of 2007, with EU ETS phase II running from 2008 to 2012. By 31 December 2006, member states should have submitted their final national allocation plan (NAP) versions. These are in the process of receiving final approval from the Commission. In 2006, our 18 EU ETS participating installations submitted their verified 2005 CO₂ emission reports, balanced their EU ETS allowance positions using BP's trading resources in London and surrendered the required number of allowances, equal to their 2005 verified annual emissions.

In September 2006, California governor Arnold Schwarzenegger signed the California Global Warming Solutions Act of 2006 (AB 32) into law. AB 32 requires the California Air Resources Board (CARB) to develop regulations that will ultimately reduce California's GHG emissions to 1990 levels by 2020 (an approximately 25% reduction from current levels). Mandatory caps will begin in 2012 for significant sources and will ratchet down over time to meet the 2020 goals. The law specifically targets "sources or categories that contribute the most to statewide emissions" for action. The California Climate Action Team, which the law designates to co-ordinate overall climate policy, has identified transportation as the largest GHG-emitting sector in California, and electricity generation and the oil and gas industry are the two largest GHG-emitting industrial sectors in the state.

The US congressional mid-term elections in November 2006 resulted in a change in control of the US Congress that may increase the prospects for more aggressive federal regulation of GHG emissions. Such future regulation could include stricter Corporate Average Fuel Emissions for automobiles sold in the US, changes in fuel specifications, the promotion of alternative fuels, stricter emissions limits on large GHG sources and/or the introduction of a cap and trade programme on CO₂ or other 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: operational emissions, which are generated from our operations such as refineries, chemicals plants and production facilities, and product emissions, generated by our customers when they use the fuels and products that we sell. Since 2001, we have been aiming to offset, through energy efficiency projects, half the underlying operational GHG emission increases that result from our growing business. After five years, we estimate that emissions growth of some 12 million tonnes has been offset by around 6 million tonnes of sustainable reductions. With regard to our products, our commitment to low-carbon businesses increased in 2006 with the internal establishment of a separate biofuels business and the announcement to establish a dedicated biosciences energy research facility attached to a major academic centre and invest

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\$500 million over the next 10 years. Our low-carbon power business, BP Alternative Energy, continued to expand its activities with the purchase of US wind developers Orion Energy, LLC, and Greenlight Energy Inc. and the formation of a strategic alliance with Clipper Windpower, to develop jointly more than 2 gigawatts of wind projects in the US.

Maritime oil spill regulations

Within the US, 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 that is financed by a tax on imported and domestic oil. This has recently been amended by the Coast Guard and Marine Transportation Act 2006 to increase the size of the fund from \$1 billion to \$2.7 billion, through the previously mentioned tax, together with an increase in the liability of double-hulled tankers from \$1,200 per gross ton to \$1,900 per gross ton. 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-hulled 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 the fourth was delivered in 2006. At the end of 2006, the ATC fleet consisted of six tankers, all double-hulled.

Outside the US, 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 ship-board 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. 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 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 OPA 90 and outside the US under the 1969/1992 International Convention on Civil Liability for Oil Pollution Damage are covered by marine liability insurance, having a maximum limit of \$1 billion for each accident or occurrence. This insurance cover is provided by three mutual insurance associations (P&I Clubs): The United Kingdom Steam Ship Assurance Association (Bermuda) Limited, The Britannia Steam Ship Insurance Association Limited and The Standard Steamship Owners' Protection and Indemnity Association (Bermuda) Limited. With effect from 20 February 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 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, so benefiting from those Clubs' pooling and reinsurance arrangements. All BP Shipping's managed and time-chartered vessels will participate in STOPIA and TOPIA.

At the end of 2006, the international fleet we managed numbered 47 oil and product carriers, all double-hulled with an average age of less than three years, seven LNG ships with an average age of nine years and three LPG ships, which are all less than one year old. The international fleet renewal programme will continue and is expected to see one more LPG ship being delivered in mid-2007 and four new LNG ships being delivered between mid-2007 and the end of 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 only double-hulled vessels by 2008; all vessels will continue to be vetted prior to each use in accordance with the BP group ship vetting policy.

US 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, stringent air emission limits and operating permits for chemicals plants, refineries, marine and distribution terminals; stricter fuel specifications and sulphur reductions; enhanced monitoring of major sources of specified pollutants; 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 affect 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 was subject to the EPA's stringent low-sulphur standards. Furthermore, by June 2006, at least 80% of the highway diesel fuel produced each year by BP was required 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 500ppm and then 15ppm by June 2012.

The Energy Policy Act of 2005 also required 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 of 4 billion gallons in 2006, increasing to 7.5 billion in 2012; consolidation of the summertime RFG Volatile organic compound (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 1psi Reid Vapor Pressure waiver for 10% ethanol blends.

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

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 over the next several years that could require, for example, 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.

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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 or otherwise named under similar state statutes at approximately 800 sites. A PRP or named party can incur 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 60 of these sites. For the remaining sites, the number of parties can range up to 200 or more. BP expects its share of remediation costs at these sites to be small in comparison with the major sites. BP has estimated its potential exposure at all sites where it has been identified as a PRP or is otherwise named 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 US 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 are likely to exceed \$350 million. Federal and state trustees also seek to recover damages for alleged injuries to natural resources in the basin. 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. However, the parties have not resolved the claims for natural resource damages on certain federal land or the State's remaining claims for restoration damages. Past settlements among the parties, including consent decree settlements providing for combined remediation and restoration projects in limited areas of the basin, may provide a framework for future settlement of the remaining claims. Atlantic Richfield Company has asserted defences to the remaining claims and has asserted counterclaims.

The group is also subject to other claims for natural resource damages (NRD) under CERCLA, OPA 90, 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 that could affect the cost of addressing environmental conditions at some sites in the future.

In the US, many environmental clean-ups 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 clean-up requirements even if the water is not being used for drinking water. Some states have even addressed contamination of non-potable 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 requirements 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 group's petroleum products such as crude oil, 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 US. These regulations require many of our US businesses to conduct security vulnerability assessments and prepare security mitigation plans that require the implementation of upgrades to security measures, the appointment and training of designated security

personnel and the submission of plans for approval and inspection by government agencies.

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 five Regional Response Incident Management Teams and seven HAZMAT Strike Teams. Collectively, these teams are ready to assist in a response to a major incident.

See also Legal proceedings on page 77.

European Union regional review

Within the EU, European Community directives are proposed by the European Commission (EC) and usually adopted jointly by the European Parliament and the Council of Ministers. They must then be implemented by each EU member state. Less frequently in the field of environment, EC regulations are adopted that apply directly throughout the EU without the need for member state implementation. When implementing EU legislation, member

states must ensure that penalties for non-compliance are effective, proportionate and dissuasive, and must usually designate a "competent authority" (regulatory body) for implementation. Where the EC believes that a member state has failed fully and correctly to transpose and implement EU legislation, it can take the member state to the European Court of Justice, which can order the member state to comply and in certain cases can impose monetary penalties on the member state. A few non-EU states may also agree to apply EU environmental legislation, in particular under the framework of the European Economic Area agreement.

An EC directive for a system of integrated pollution prevention and control (IPPC) was adopted in 1996. This system requires certain industrial installations "including most activities and processes undertaken by the oil and petrochemicals industry within the EU" to obtain an IPPC permit, which is designed to address an installation's environmental impacts, air emissions, water discharges and waste in a comprehensive fashion. The permit requires, among other things, the application of Best Available Techniques (BAT), taking into account the costs and benefits, unless an applicable environmental quality standard requires more stringent restrictions, and an assessment of existing environmental impacts and future site closure obligations. All such plants must apply for and obtain such a permit by November 2007. Compliance requires capital and revenue expenditure across BP sites. The EC has embarked upon a process of review that is likely to report in 2007 and to result in recommendations for amendments to the IPPC directive.

The EC Large Combustion Plant Directive was adopted in 1988 and subsequently replaced by a new Large Combustion Plant Directive in 2001. The current LCPD imposes a complex range of controls on emissions of sulphur dioxide, nitrogen oxides and particulates from large combustion plants. The nature and stringency of these controls for a particular plant depend principally on its age. Plants permitted between 1987 and 2002 had a requirement for specific emission limit values by 27 November 2002. Plants permitted since then must meet more stringent emission limit values. Plants permitted prior to 1987 must also meet emission limit values unless they have "opted out" (in which case they must now close after 20,000 hours of further operation starting from 1 January 2008 and ending no later than 31 December 2015) or will participate in a National Emission Reduction Plan designed to deliver equivalent aggregate emission reductions.

The second important set of air quality-related legislation affecting BP European operations is the Air Quality Framework Directive on ambient air quality assessment and management and its daughter Directives, 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. If the concentration of a pollutant exceeds air quality limit values plus a margin of tolerance set under a daughter Directive (or there is a risk of such exceedance), a member state is required to take action to reduce emissions. This may affect any BP operations whose emissions contribute to such exceedances.

In 2005, the EC published its Thematic Strategy on Air Pollution "a key part of the "Clean Air for Europe" (CAFÉ) programme" and an accompanying proposed directive to consolidate the existing ambient air quality legislation referred to above and to introduce new controls on the

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concentration of fine particles (PM 2.5 – particulate matter less than 2.5 microns diameter) in ambient air. The Thematic Strategy 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 50ppm 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 10ppm 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 during 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 19 August 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.

A new EC programme for European chemical regulation – REACH (Registration, Evaluation and Authorization of Chemicals) will come into force on 1 June 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 and a registration within a 3-to 11-year time-phased period from adoption. The actual date depends on volume bands or classification with high volumes and hazardous substances first. Only time-limited authorizations will be given to substances of "high concern". A new European Chemical Agency will be established in Helsinki by mid-2008. Crude oil and natural gas are exempt. Fuels will be exempted from authorization but not registration. For BP, REACH will affect all refining petroleum products, petrochemicals, lubricants and other chemicals. An initial estimate suggests costs of about \$60,000 each for the internal preparation, pre-registration and registration of nearly 1,000 entities representing manufactured or imported substances or imported preparations for all BP individual entities obligated under REACH. Additional costs for further submission to authorization for relevant substances and the modification of safety data sheets will have to be assessed as further costs once the final regulation is known.

The EC adopted a Directive on Environmental Liability on 21 April 2004. From 30 April 2007, member states must usually require the operators of activities that cause significant damage to water, ecological resources or land after that date to undertake restoration of that damage. Provision is also made for reporting and tackling imminent threats of such damage. The regime is more stringent for operators of specified higher-risk activities, including IPPC-permitted operations. Member states are considering how to implement the regime.

During 2007, the commission is expected to release a communication on Carbon Capture and Storage (CCS), setting out guidelines for the technology and its regulation. The intention of the communication is in part to identify regulatory barriers that may restrict CCS technologies, so that those barriers can be appropriately addressed, and to identify common methodologies to be implemented across EU member states.

Other environment-related existing regulations that may have an impact on BP's operations include: the Major Hazards Directive which, for the sites to which it applies, 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 surface waters and groundwater; and the Waste Framework Directive.

The Water Framework Directive requires member states to develop "programmes of measures" and start implementing them by 2012, the principal objective being to ensure that all water bodies covered by the directive attain at least "good quality" by 2015. For an individual plant which, for instance, abstracts water or discharges effluent into water, the implications of the directive will depend on local circumstances (including the extent to which the activity might prejudice attaining "good quality" for a water body) and on the individual member state's approach to developing and implementing the relevant programme of measures. The Water Framework Directive also draws together and provides for the replacement (with new directives) of a number of other directives relating to water quality, such as those on groundwater and discharge of dangerous substances.

The Waste Framework Directive requires member states to operate a permitting regime for waste disposal and recovery and to ensure that waste is recovered or disposed without endangering human health and without using processes or methods that could harm the environment. A European Court of Justice ruling in 2004 (Van de Walle) interpreted these requirements widely, in a way that raised potentially significant implications for soil and groundwater contamination; however, a proposed revision to the directive that is currently making its way through the EU legislative process would, if adopted in its current form, potentially pave the way for mitigating this position by excluding from the directive unexcavated soil covered by other EU legislation.

In 2005, the EC published a proposed EC Marine Strategy Directive, which would adopt an approach akin to that

in the Water Framework Directive by requiring achievement of "good environmental status" for marine waters by 2021 through the implementation of programmes of measures.

In 2006, the EC published a proposed Soil Framework Directive that, as currently drafted, would encompass all soils, not just those for agricultural uses. If adopted in its current form, the directive would require member states to develop, over time, a register of "contaminated sites" and to require their remediation so that they do not pose significant risks to human health or the environment. Unlike the Environmental Liability Directive, this is intended to apply to historic as well as new contamination. Member states may well need to carry out or require intrusive site investigations in order to establish whether particular sites are "contaminated sites"; coupled with a requirement (which will be new for some member states) for site investigations to be carried out on any sale of land that may be contaminated, this could lead to the crystallization of liabilities for BP in respect of its current or former operational and other land holdings, if any such land is found to be contaminated.

Property, plants and equipment

BP has freehold and leasehold interests in real estate in numerous countries throughout the world, but no individual property is significant to the group as a whole. See Exploration and Production on page 12 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 section.

Organizational structure

The significant subsidiaries of the group at 31 December 2006 and the group percentage of ordinary share capital (to nearest whole number) are set out in Financial statements – Note 50 on page 161. See Financial statements – Notes 29, 30 and 55 on pages 127, 128 and 185 respectively for information on significant jointly controlled entities and associates of the group.

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