BP PLC
Form 20-F
March 04, 2008

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 December 31, 2007
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)

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(Name, Telephone, Email and/or Facsimile number and Address of Company Contact Person)
Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Ordinary Shares of 25c each	**New York Stock Exchange*** **Chicago Stock Exchange***
4 7/8% Guaranteed Notes due 2010	**New York Stock Exchange**

Floating Rate Guaranteed Extendible Notes	**New York Stock Exchange**
	*Not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

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

None

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

None

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

Ordinary Shares of 25c each	**18,922,785,598**
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 basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP International Financial Reporting Standards as issued by the International Accounting Standards Board Other

If Other has been checked in response to the previous question, 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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Cross reference to Form 20-F

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Certain definitions

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

Oil and natural gas reserves

Oil and gas reserves Proved reserves are defined by the Securities and Exchange Commission (SEC) in Rule 410(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 shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be 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 for 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

In this document, unless the context otherwise requires, the following terms shall have the meaning set out below.

ADR American depositary receipt.

ADS American depositary share.

AGM Annual general meeting.

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 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.

Baker Panel, or panel BP US Refineries Independent Safety Review Panel.

Barrel 42 US gallons.

b/d barrels per day.

boe barrels of oil equivalent.

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.

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.

mmboe million barrels of oil equivalent.

mmcf million cubic feet.

mmcf/d million cubic feet per day.

MTBE Methyl tertiary butyl ether.

MW Megawatt.

NGLs Natural gas liquids.

OPEC Organization of Petroleum Exporting Countries.

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

Pence or p One-hundredth of a pound sterling.

Pound, sterling or £ The pound sterling.

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

PSA Production-sharing agreement.

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.

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.

US United States of America.

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Performance review

Selected financial and operating information

This information, insofar as it relates to 2007, has been extracted or derived from the audited financial statements of the BP group presented on pages 93-180. Note 1 to the Financial statements includes details on the basis of preparation of these financial statements. The selected information should be read in conjunction with the audited financial statements and related Notes elsewhere herein.

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.

$ million except per share amounts

	2007	2006	2005	2004	2003
Income statement data					
Sales and other operating revenues from continuing operations[a]	**284,365**	265,906	239,792	192,024	164,653
Profit before interest and taxation from continuing operations[a]	**32,352**	35,658	32,182	25,746	18,776
Profit from continuing operations[a]	**21,169**	22,626	22,133	17,884	12,681
Profit for the year	**21,169**	22,601	22,317	17,262	12,618
Profit for the year attributable to BP shareholders	**20,845**	22,315	22,026	17,075	12,448
Capital expenditure and acquisitions[b]	**20,641**	17,231	14,149	16,651	19,623
Per ordinary share cents					
Profit for the year attributable to BP shareholders					
Basic	**108.76**	111.41	104.25	78.24	56.14
Diluted	**107.84**	110.56	103.05	76.87	55.61
Profit from continuing operations attributable to BP shareholders					
Basic	**108.76**	111.54	103.38	81.09	56.42
Diluted	**107.84**	110.68	102.19	79.66	55.89
Dividends paid per share cents	**42.30**	38.40	34.85	27.70	25.50
pence	**20.995**	21.104	19.152	15.251	15.658
Ordinary share data[c]					
Average number outstanding of 25 cent ordinary shares (shares million undiluted)	**19,163**	20,028	21,126	21,821	22,171

Average number outstanding of 25 cent ordinary shares (shares million diluted)	**19,327**	20,195	21,411	22,293	22,424
Balance sheet data					
Total assets	**236,076**	217,601	206,914	194,630	172,491
Net assets	**94,652**	85,465	80,450	78,235	70,264
Share capital	**5,237**	5,385	5,185	5,403	5,552
BP shareholders equity	**93,690**	84,624	79,661	76,892	69,139
Finance debt due after more than one year	**15,651**	11,086	10,230	12,907	12,869
Net debt to net debt plus equity	**23%**	20%	17%	22%	22%

[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 3 on page 110.*)

[b] 2007 included $1,132 million for the acquisition of Chevron s Netherlands manufacturing company. There were no significant acquisitions in 2006 or in 2005. Capital expenditure in 2006 included $1 billion in respect of our investment in Rosneft. Capital expenditure and acquisitions for 2004 included $1,354 million for including TNK s interest in Slavneft within TNK-BP and $1,355 million for the acquisition of Solvay s interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America.

Capital expenditure and acquisitions for 2003 included $5,794 million for the acquisition of our interest in TNK-BP. 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 past five years have been financed from cash flow from operations, disposal proceeds and external financing.

[c] The number of ordinary shares shown has been used to calculate per share amounts.

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Production and net proved oil and natural gas reserves

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

Production and net proved reserves[a]

	2007	2006	2005	2004	2003
Crude oil production for subsidiaries (thousand barrels per day)	**1,304**	1,351	1,423	1,480	1,615
Crude oil production for equity-accounted entities (thousand barrels per day)	**1,110**	1,124	1,139	1,051	506
Natural gas production for subsidiaries (million cubic feet per day)	**7,222**	7,412	7,512	7,624	8,092
Natural gas production for equity-accounted entities (million cubic feet per day)	**921**	1,005	912	879	521
Estimated net proved crude oil reserves for subsidiaries (million barrels)[b]	**5,492**	5,893	6,360	6,755	7,214
Estimated net proved crude oil reserves for equity-accounted entities (million barrels)[c]	**4,581**	3,888	3,205	3,179	2,867
Estimated net proved natural gas reserves for subsidiaries (billion cubic feet)[d]	**41,130**	42,168	44,448	45,650	45,155
Estimated net proved natural gas reserves for equity-accounted entities (billion cubic feet)[e]	**3,770**	3,763	3,856	2,857	2,869

[a] Crude oil includes natural gas liquids (NGLs) and condensate. Production and proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option to make lifting and sales arrangements independently, and include minority interests in consolidated operations.

[b] Includes 20 million barrels (23 million barrels at 31 December 2006 and 29 million barrels at 31 December 2005) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[c] Includes 210 million barrels (179 million barrels at 31 December 2006 and 95 million barrels at 31 December 2005) in respect of the 6.51% minority interest in TNK-BP (6.29% at 31 December 2006 and 4.47% at 31 December 2005).

[d] Includes 3,211 billion cubic feet of natural gas (3,537 billion cubic feet at 31 December 2006 and 3,812 billion cubic feet at 31 December 2005) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[e] Includes 68 billion cubic feet (99 billion cubic feet at 31 December 2006 and 57 billion cubic feet at 31 December 2005) in respect of the 5.88% minority interest in TNK-BP (7.77% at 31 December 2006 and 4.47% at 31 December 2005).

During 2007, 414 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 937mmboe, BP s proved reserves for subsidiaries were 12,583mmboe at 31 December 2007. These proved reserves are mainly located in the US (46%), Rest of Americas (19%), Asia Pacific (10%), Africa (8%) and the UK (8%).

For equity-accounted entities, 1,168mmboe were added to proved reserves (excluding purchases and sales), production was 470mmboe and proved reserves were 5,231mmboe at 31 December 2007.

* 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. Lack of material positions in new markets and/or inability to complete disposals 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 and the outcome of meetings of OPEC can particularly affect world supply and oil prices. Previous oil price increases have resulted in increased fiscal take, cost inflation and more onerous terms for access to resources. As a result, increased oil prices may not improve margin performance. 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.

Climate change and carbon pricing

Compliance with changes in laws, regulations and obligations relating to climate change could result in substantial capital expenditure, reduced profitability from changes in operating costs and revenue generation and strategic growth opportunities being impacted.

Socio-political

We have operations in 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. The implementation of group strategy requires continued technological advances and innovation including advances in exploration, production, refining, petrochemical manufacturing technology and advances in technology related to energy usage. Our performance could be impeded if competitors developed or acquired intellectual property rights to technology that we required or if our innovation lagged the industry.

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 to determine adequately 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.

For further information on financial instruments and financial risk factors see Financial statements Note 28 on page 136 and Note 34 on page 143.

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.

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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 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, sea or pipeline. 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 (see page 11) 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 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 implementing our plans. Inability to develop the human capacity and capability across the organization could jeopardize performance delivery.

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Forward-looking statements

In order to utilize the Safe Harbor provisions of the United States Private Securities Litigation Reform Act of 1995, BP is providing the following cautionary statement. This document contains certain forward-looking statements with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , should , may , objective , is likely to , intends , believes , plans , we see or similar expressions. In particular, among other statements, (statements in Performance review (pages 6-55) with regard to management aims and objectives, future capital expenditure, future hydrocarbon production volume, date(s) or period(s) in which production is scheduled or expected to come onstream or a project or action is scheduled or expected to begin or be completed, capacity of planned plants or facilities and impact of health, safety and environmental regulations; (ii) the statements in Performance review (pages 6-44) with regard to planned expansion, investment or other projects and future regulatory actions; and (iii) the statements in Performance review (pages 45-55) with regard to the plans of the group, cash flows, opportunities for material acquisitions, the cost of and provision for 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 production, future refining availability, future capital expenditure, sources of funding, future revenues and financial performance, potential for cost efficiencies, level of free cash flow allocated to share buybacks, shareholder distributions and share buybacks, gearing, working capital and expected payments under contractual and commercial commitments; 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 onstream; 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 on pages 8-9. 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 company, 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, tel +44 (0)20 7496 4000. Our agent in the US is BP America Inc., 4101 Winfield Road, Warrenville, Illinois 60555, tel +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 covered three business segments in 2007, supported by a number of organizational elements comprising group functions and regions.

In 2007, the three business segments were Exploration and Production, Refining and Marketing and Gas, Power and Renewables. With effect from 1 January 2008, the Gas, Power and Renewables segment ceased to report separately *(see Resegmentation in 2008 on page 12)*. 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 the supply and trading, refining, marketing and transportation of crude oil, petroleum and chemicals products. Gas, Power and Renewables activities included 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 system of internal control addresses risks and how to respond to them. Each component of the system 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 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 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 65% 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 Europe.

We believe that BP has a strong portfolio of assets:

- In Exploration and Production, we have upstream interests in 29 countries. 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 current areas of major development include the deepwater Gulf of Mexico, Azerbaijan, Algeria, Angola, Egypt and Asia Pacific where we believe we have competitive advantage and that 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. In the US, we market under the Amoco and BP brands in the Midwest, east and southeast and under the ARCO brand on the west coast, 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 & 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 growth markets such as China and India.
- In our Gas, Power and Renewables businesses, marketing and trading is undertaken primarily in the US, Canada, the UK and the rest of Europe. Our marketing and trading activities include natural gas, power and NGLs. Our LNG activities identify and capture worldwide opportunities for our upstream natural gas resources and are focused on growing natural gas markets, including the US, the UK, Spain and key consuming countries of the Asia Pacific region. We have a significant NGLs processing and marketing business in North America. BP Alternative Energy, launched in November 2005, combines all of BP s interests in businesses that provide low-carbon energy solutions for power generation: solar, wind, gas-fired power generation and hydrogen power with carbon capture and storage. Alternative Energy has solar production facilities in the US, Spain, China, India and Australia; and wind farms in the Netherlands, India and the US. We are advancing development of hydrogen power plants and are involved in gas-fired power projects in the US, the UK, Spain, Vietnam, Trinidad & Tobago and South Korea.

Through non-US subsidiaries or other non-US entities, during the period covered by this report, BP conducted limited marketing, licensing and trading activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of Terrorism. BP believes that these activities are immaterial to the group.

BP has interests in, and is the operator of, two fields and a pipeline located outside of Iran in which the National Iranian Oil Company (NIOC) and an affiliated entity have interests. In Iran, BP buys small quantities of crude oil. This is primarily for sale to third parties in Europe and a small portion is used by BP in its own refineries in South Africa and Europe. In addition, BP sells small quantities of crude oil into Iran and blends and markets small quantities of lubricants for sale to domestic consumers through a joint venture there, which has a blending facility. However, BP does not seek to obtain from the government of Iran licences or agreements for oil and gas projects in Iran, is not conducting any technical studies in Iran and does not own or operate any refineries or chemicals plants in Iran.

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BP sells small quantities of lubricants in Cuba through a 50/50 joint venture there. In Syria, small quantities of lubricants are sold through a distributor and BP obtains small volumes of crude oil supplies for sale to third parties in Europe. These sales and purchases are insignificant and BP does not provide other goods, technologies or services in these countries.

Acquisitions and disposals

In 2007, BP acquired Chevron s Netherlands manufacturing company, Texaco Raffinidérij Pernis B.V. The acquisition included 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 a 22.8% shareholding in the TEAM joint venture terminal and shareholdings in two local pipelines linking the TEAM terminal to the refinery. Disposal proceeds were $4,267 million, which included $1,903 million from the sale of the Coryton refinery and $605 million from the sale of our exploration and production gas infrastructure business in the Netherlands.

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 represented 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.

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.

Resegmentation in 2008

On 11 October 2007, we announced our intention to simplify the organizational structure of BP. From 1 January 2008, there are only two business segments: Exploration and Production and Refining and Marketing. A separate business, Alternative Energy, handles BP s low-carbon businesses and future growth options outside oil and gas.

As a result, and with effect from 1 January 2008:

- The Gas, Power and Renewables segment ceased to report separately.
- The NGLs, LNG and gas and power marketing and trading businesses were transferred from the Gas, Power and Renewables segment to the Exploration and Production segment.
- The Alternative Energy business was transferred from the Gas, Power and Renewables segment to Other businesses and corporate.
- The Emerging Consumers Marketing Unit was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
- The Biofuels business was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
- The Shipping business was transferred from Refining and Marketing to Other businesses and corporate.

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Exploration and Production

Our Exploration and Production segment includes upstream and midstream activities in 29 countries, including the US, the UK, Angola, Azerbaijan, Canada, Egypt, Russia, Trinidad & Tobago (Trinidad) and locations within Asia Pacific, Latin America, North Africa 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, Algeria, Angola, Azerbaijan, Egypt and Russia. Major development areas include the deepwater Gulf of Mexico, Azerbaijan, Algeria, Angola, Egypt and Asia Pacific. During 2007, 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
	2007	2006	2005
Sales and other operating revenues from continuing operations	**54,550**	52,600	47,210
Profit before interest and tax from continuing operations[a]	**26,938**	29,629	25,502
Total assets	**108,874**	99,310	93,447
Capital expenditure and acquisitions	**13,906**	13,118	10,237
			million barrels of oil equivalent
Net proved reserves group	**12,583**	13,163	14,023
Net proved reserves equity-accounted entities	**5,231**	4,537	3,870
			thousand barrels per day
Liquids production group	**1,304**	1,351	1,423
Liquids production equity-accounted entities	**1,110**	1,124	1,139
			million cubic feet per day
Natural gas production group	**7,222**	7,412	7,512
Natural gas production equity-accounted entities	**921**	1,005	912
			$ per barrel
Average BP crude oil realizations[b]	**69.98**	61.91	50.27
Average BP NGL realizations[b]	**46.20**	37.17	33.23
Average BP liquids realizations[b c]	**67.45**	59.23	48.51

Average West Texas Intermediate oil price	**72.20**	66.02	56.58
Average Brent oil price	**72.39**	65.14	54.48

			$ per thousand cubic feet
Average BP natural gas realizations[b]	**4.53**	4.72	4.90
Average BP US natural gas realizations[b]	**5.43**	5.74	6.78

			$ per million British thermal units
Average Henry Hub gas price[d]	**6.86**	7.24	8.65

			pence per therm
Average UK National Balancing Point gas price	**29.95**	42.19	40.71

a Profit before interest and tax from continuing operations includes profit after interest and tax of equity-accounted entities.
b The Exploration and Production segment does not undertake any hedging activity. Consequently, realizations reflect the market price achieved. Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.
c Crude oil and natural gas liquids.
d Henry Hub First of Month Index.

Upstream operations in Argentina, Bolivia, Abu Dhabi, Kazakhstan and the TNK-BP and some of the 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 by:

Focusing on finding the largest fields in 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.

Through the application of advanced technology and significant investment, we have gained a strong position in many of our operating areas.

Total capital expenditure and acquisitions in 2007 was $13.9 billion (2006 $13.1 billion and 2005 $10.2 billion). There were no significant acquisitions in the period from 2005 to 2007. Capital expenditure in 2006 included our investment in Rosneft s IPO of $1 billion. Capital expenditure in 2008 is planned to be around $15 billion including approximately $0.5 billion in respect of the gas and power businesses that are now reported through Exploration and Production, as described below, and excluding the impact of our transaction with Husky Energy Inc., which is further described on page 21. 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 2007, excluding midstream activities, was $10,153 million, compared with $9,109 million in 2006 and $7,678 million in 2005.

Resegmentation in 2008

With effect from 1 January 2008, the NGLs, LNG and the gas and power marketing and trading businesses were transferred from the Gas, Power and Renewables segment to the Exploration and Production segment.

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 2007 were $1,892 million, compared with $1,765 million in 2006 and $1,266 million in 2005. 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. Approximately 47% of 2007 exploration and appraisal costs were directed towards appraisal activity. In 2007, we participated in 86 gross (37 net) exploration and appraisal wells in 12 countries. The principal areas of activity were the deepwater Gulf of Mexico, Angola, Egypt, North Sea, Canada and Pakistan.

Total exploration expense in 2007 of $756 million (2006 $1,045 million and 2005 $684 million) included the write-off of expenses related to

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unsuccessful drilling activities in Russia ($86 million excluding TNK-BP), Egypt ($49 million), Colombia ($49 million), the deepwater Gulf of Mexico ($36 million), onshore North America ($36 million), Angola ($27 million) and others ($11 million).

In 2007, we obtained upstream rights in several new tracts, which include the following:

– In the Gulf of Mexico, we have been awarded 171 blocks (BP average equity 100%) through the Outer Continental Shelf Lease Sales 204 and 205.
– In Oman, we signed a production-sharing agreement (PSA) to appraise and develop the Khazzan/Makarem gas fields.
– In Colombia, BP was awarded operatorship in two blocks, RC4 (BP 35%) and RC5 (BP 100%), which cover approximately 6,200 square kilometres in the Caribbean Sea, offshore northern Colombia.
– In Libya, BP signed a major exploration and production agreement with Libya s National Oil Company, covering over 53,000 square kilometres both onshore and offshore.

In 2007, we were involved in a number of discoveries. In most cases, reserves bookings from these fields will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling. Our most significant discoveries in 2007 included the following:

– In Angola, we made further discoveries in the ultra deepwater (greater than 1,500 metres) Block 31 (BP 26.7% and operator) with the Miranda, Cordelia and Portia wells, bringing the total number of discoveries in Block 31 to 15.
– In Azerbaijan, we made a further discovery in a new reservoir in Shah Deniz (BP 25.5% and operator) with the SDX-04 well.
– In Egypt, we made three discoveries with the Giza North-1 (BP 60% and operator), Taurus Deep (BP 60% and operator) and Satis (BP 50% and operator) wells.
– In the deepwater Gulf of Mexico, we made a discovery with the Isabela well (BP 67% and operator).

Reserves and production

Compliance

IFRS does not provide specific guidance on reserves disclosures. BP estimates proved reserves in accordance with SEC Rule 4-10 (a) and relevant guidance notes and letters issued by the SEC staff.

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.

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 2007, 16% were based on estimates prepared by group petroleum engineers and 84% were based on estimates prepared by independent engineering consultants, although all of the group s oil and gas reserves held in equity-accounted entities 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 agreements where the group is exposed to the upstream risks and rewards of ownership, but where title to the hydrocarbons is not conferred, such as 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. Thirteen 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.

We separately disclose our share of reserves held in equity-accounted entities (jointly controlled entities and associates), although we do not control these entities or the assets held by such entities.

Resource progression

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 of PUD reserves 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.

Governance

BP s centrally controlled process for proved reserves estimation approval forms part of a holistic and integrated system of internal control. It consists of the following elements:

- Accountabilities of certain officers of the group to ensure that there is review and approval of proved reserves bookings independent of the operating business and that there are effective controls in the approval process and verification that the proved reserves estimates and the related financial impacts are reported in a timely manner.
- 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.
- 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.
- Approval hierarchy whereby proved reserves changes above certain threshold volumes require central authorization and periodic reviews.

  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 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 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.

Reserve replacement

Total hydrocarbon proved reserves, on an oil equivalent basis and excluding equity-accounted entities, comprised 12,583mmboe at 31 December 2007, a decrease of 4.4% compared with 31 December 2006. Natural gas represents about 56% of these reserves. The reduction includes net sales of 58mmboe, largely comprising a number of assets in the Netherlands, Pakistan, Canada and the US.

Total hydrocarbon proved reserves, on an oil equivalent basis for equity-accounted entities alone, comprised 5,231mmboe at 31 December 2007, an increase of 15.3% compared with 31 December 2006. Natural gas represents about 12% of these proved reserves. The increase includes net sales of 3mmboe, largely comprising a number of assets in Russia.

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 ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery and extensions and discoveries, and may be expressed as a replacement ratio excluding acquisitions and divestments or as a total replacement ratio including acquisitions and divestments.

			%
	2007	2006	2005
Proved reserves replacement ratio, excluding equity-accounted entities	**44**	34	68
Proved reserves replacement ratio, excluding equity-accounted entities, including sales and purchases of reserves-in-place	**38**	11	40
Proved reserves replacement ratio, for equity-accounted entities	**248**	272	151
Proved reserves replacement ratio, for equity-accounted entities, including sales and purchases of reserves-in-place	**248**	239	141
			million barrels of oil equivalent
Additions to proved developed reserves, excluding equity-accounted entities, including sales and purchases of reserves-in-place[a]	**929**	675	632
Additions to proved developed reserves, for equity-accounted entities, including sales and purchases of reserves-in-place[a]	**473**	936	474
			%
Proved developed reserves replacement ratio, excluding equity-accounted entities, including sales and purchases of reserves-in-place	**99**	70	63
Proved developed reserves replacement ratio, for equity-accounted entities, including sales and purchases of reserves-in-place	**101**	195	99

a This includes some reserves that were previously classified as proved undeveloped.

In 2007, net additions to the group s proved reserves (excluding sales and purchases of reserves-in-place and equity-accounted entities) amounted to 414mmboe, principally through improved recovery from, and extensions to, existing fields and discoveries of new fields. Of the reserves additions through improved recovery from, and extensions to, existing fields and discoveries of new fields, 64% 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. The principal reserves additions were in the Norway (Skarv), the US (Liberty, Prudhoe Bay, Great White, Nakika, Thunder Horse), Trinidad (Immortelle, Manakin), Angola (Pazflor) and Canada (Noel).

Production

Our total hydrocarbon production during 2007 averaged 2,549 thousand barrels of oil equivalent per day (mboe/d) for subsidiaries and 1,269mboe/d for equity-accounted entities, a decrease of 3% and 2% respectively compared with 2006. For subsidiaries, 35% of our production was in the US and 13% in the UK. For equity-accounted entities, 72% of production was from TNK-BP.

Total production for 2008 is expected to be higher than in 2007. This is based on the group s asset portfolio at 1 January 2008, expected startups in 2008 and Brent at $60/bbl, before any 2008 disposal effects and before any effects of prices above $60/bbl on volumes in PSAs.

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The following tables show BP s estimated net proved reserves as at 31 December 2007.

Estimated net proved reserves of liquids at 31 December 2007[a b c]

			million barrels
	Developed	Undeveloped	Total
UK	414	123	537
Rest of Europe	105	169	274
US	1,882	1,265	3,147[d]
Rest of Americas	115	203	318[e]
Asia Pacific	61	77	138
Africa	256	350	606
Russia			
Other	104	368	472
Group	2,937	2,555	5,492
Equity-accounted entities	2,996	1,585	4,581[f]

Estimated net proved reserves of natural gas at 31 December 2007[a b c]

			billion cubic feet
	Developed	Undeveloped	Total
UK	2,049	553	2,602
Rest of Europe	63	410	473
US	10,670	4,705	15,375
Rest of Americas	3,683	8,394	12,077[g]
Asia Pacific	1,822	4,817	6,639
Africa	990	1,410	2,400
Russia			
Other	583	981	1,564
Group	19,860	21,270	41,130
Equity-accounted entities	2,473	1,297	3,770[h]

Net proved reserves on an oil equivalent basis (mmboe)

Group	6,361	6,222	12,583
Equity-accounted entities	3,422	1,809	5,231

a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently, 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 2007, 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, 19 are in production and one, Thunder Horse, is expected to begin production by the end of 2008. Two other fields are in the early stages of development.

[c] The 2007 year-end marker prices used were Brent $96.02/bbl (2006 $58.93/bbl and 2005 $58.21/bbl) and Henry Hub $7.10/mmBtu (2006 $5.52/mmBtu and 2005 $9.52/mmBtu).

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 98 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[e] Includes 20 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[f] Includes 210 million barrels of crude oil in respect of the 6.51% minority interest in TNK-BP.

[g] Includes 3,211 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[h] Includes 68 billion cubic feet of natural gas in respect of the 5.88% minority interest in TNK-BP.

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The following tables show BP s production by major field for 2007, 2006 and 2005.

Liquids

		%	thousand barrels per day BP net share of production[a]		
	Field or Area	Interest	**2007**	2006	2005
Alaska	Prudhoe Bay[b]	26.4	**74**	71	89
	Kuparuk	39.2	**52**	57	62
	Northstar[b]	98.6	**28**	38	46
	Milne Point[b]	99.4	**28**	31	37
	Other	Various	**27**	27	34
Total Alaska			**209**	224	268
Lower 48 onshore[c]	Various	Various	**108**	125	130
Gulf of Mexico deepwater[c]	Na Kika[b]	50.0	**32**	41	44
	Horn Mountain[b]	100.0	**18**	23	26
	King[b]	100.0	**22**	28	24
	Mars	28.5	**30**	19	21
	Mad Dog[b]	61.0	**25**	17	13
	Holstein[b]	50.0	**17**	15	22
	Other	Various	**52**	52	48
Gulf of Mexico Shelf[c]	Other	Various		3	16
Total Gulf of Mexico			**196**	198	214
Total US			**513**	547	612
UK offshore[c]	ETAP[d]	Various	**32**	49	49
	Foinaven[b]	Various	**37**	37	39
	Magnus[b]	85.0	**16**	30	30
	Schiehallion/Loyal[b]	Various	**20**	26	28
	Harding[b]	70.0	**14**	17	22
	Andrew[b]	62.8	**8**	7	12
	Other	Various	**59**	69	75
Total UK offshore			**186**	235	255
Onshore	Wytch Farm[b]	67.8	**15**	18	22
Total UK			**201**	253	277
Netherlands[c]	Various	Various		1	1
Norway	Valhall[b]	28.1	**17**	21	25
	Draugen	18.4	**14**	15	20
	Ula[b]	80.0	**12**	14	17

	Other	Various	**8**	10	12
Total Rest of Europe			**51**	61	75
Angola	Dalia	16.7	**31**		
	Girassol	16.7	**14**	17	34
	Greater Plutonio[b]	50.0	**12**		
	Kizomba A	26.7	**36**	54	56
	Kizomba B	26.7	**35**	58	28
	Other	Various	**11**	4	10
Australia	Various	15.8	**34**	34	36
Azerbaijan	Azeri-Chirag-Gunashli[b]	34.1	**200**	145	76
	Shah Deniz[b]	25.5	**5**		
Canada[c]	Various[b]	Various	**8**	8	10
Colombia	Various[b]	Various	**28**	34	41
Egypt	Various	Various	**43**	42	47
Trinidad & Tobago[c]	Various[b]	100.0	**30**	40	40
Venezuela[c]	Various	Various	**16**	26	55
Other[c]	Various	Various	**36**	28	26
Total Rest of World			**539**	490	459
Total group[e]			**1,304**	1,351	1,423
Equity-accounted entities (BP share)					
Abu Dhabi[f]	Various	Various	**192**	163	148
Argentina Pan American Energy	Various	Various	**69**	69	67
Russia TNK-BP	Various	Various	**832**	876	911
Other[c]	Various	Various	**17**	16	13
Total equity-accounted entities			**1,110**	1,124	1,139

[a] Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

[b] BP-operated.

[c] In 2007, BP divested its producing properties in the Netherlands and some producing properties in the US Lower 48 and Canada. TNK-BP disposed of its interests in several non-core properties. 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, Desarollo 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 Udmurtneft 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, and TNK-BP disposed of non-core producing assets in the Saratov region.

[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 54 net mboe/d of NGLs from processing plants in which BP has an interest (2006 55mboe/d and 2005 58mboe/d).

[f] The BP group holds interests, through associates, in onshore and offshore concessions in Abu Dhabi, expiring in 2014 and 2018 respectively. During the second quarter of 2007, we updated our reporting policy in Abu Dhabi to be consistent with general industry practice and as a result have started reporting production and reserves there gross of production taxes. This change resulted in an increase in our reserves of 153 million barrels and in our production of 33 thousand barrels per day (mb/d).

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Natural gas		%		million cubic feet per day BP net share of production[a]	
	Field or Area	Interest	**2007**	2006	2005
Lower 48 onshore[b]	San Juan[c]	Various	**694**	765	753
	Arkoma[c]	Various	**204**	225	198
	Hugoton[c]	Various	**123**	137	151
	Tuscaloosa[c]	Various	**78**	86	111
	Wamsutter[c]	70.5	**120**	113	110
	Jonah[c]	65.0	**173**	133	97
	Other	Various	**458**	461	465
Total Lower 48 onshore			**1,850**	1,920	1,885
Gulf of Mexico deepwater[b]	Na Kika[c]	50.0	**50**	97	133
	Marlin[c]	78.2	**13**	16	52
	Other	Various	**205**	210	235
Gulf of Mexico Shelf[b]	Other	Various	**1**	66	160
Total Gulf of Mexico			**269**	389	580
Alaska	Various	Various	**55**	67	81
Total US			**2,174**	2,376	2,546
UK offshore[b]	Braes[d]	Various	**69**	101	165
	Bruce[c]	37.0	**72**	107	161
	West Sole[c]	100.0	**55**	56	55
	Marnock[c]	62.0	**25**	42	47
	Britannia	9.0	**37**	42	46
	Shearwater	27.5	**19**	31	37
	Armada	18.2	**16**	28	30
	Other	Various	**475**	529	549
Total UK			**768**	936	1,090
Netherlands[b]	P/18-2[c]	48.7		23	25
	Other	Various	**3**	33	37
Norway	Various	Various	**26**	35	46
Total Rest of Europe			**29**	91	108
Australia	Various	15.8	**376**	364	367
Canada[b]	Various[c]	Various	**255**	282	307
China	Yacheng[c]	34.3	**85**	102	98

Egypt	Hapy[c]	50.0	**108**	99	106
	Other	Various	**206**	172	83
Indonesia	Sanga-Sanga(direct)[c]	26.3	**75**	84	110
	Other[c]	46.0	**81**	80	128
Sharjah	Sajaa[c]	40.0	**83**	111	113
	Other	40.0	**9**	9	10
Azerbaijan	Shah Deniz[c]	25.5	**73**		
Trinidad & Tobago[b]	Kapok[c]	100.0	**984**	946	1,005
	Mahogany[c]	100.0	**454**	321	303
	Amherstia[c]	100.0	**155**	176	289
	Parang[c]	100.0		120	154
	Immortelle[c]	100.0	**153**	219	132
	Cassia[c]	100.0	**25**	30	83
	Other[c]	100.0	**663**	453	21
Other[b]	Various	Various	**466**	441	459
Total Rest of World			**4,251**	4,009	3,768
Total group[e]			**7,222**	7,412	7,512
Equity-accounted entities (BP share)					
Argentina Pan American Energy	Various	Various	**379**	362	343
Russia TNK-BP[b]	Various	Various	**451**	544	482
Other[b]	Various	Various	**91**	99	87
Total equity-accounted entities[e]			**921**	1,005	912

[a] Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

[b] In 2007, BP divested its producing properties in the Netherlands and some producing properties in the US Lower 48 and Canada. TNK-BP disposed of its interests in several non-core properties. 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, Desarollo 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 Udmurtneft 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, and TNK-BP disposed of non-core producing assets in the Saratov region.

[c] BP-operated.

[d] Includes 4 million cubic feet per day (mmcf/d) of natural gas received as in-kind tariff payments in 2005. None received in 2006 and 2007.

[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

2007 liquids production at 513mb/d decreased 6% from 2006, while natural gas production at 2,174mmcf/d decreased 8% compared with 2006.

Crude oil production showed a moderate decline of 18mb/d from 2006, with production from new projects (Gulf of Mexico) being offset by divestments and natural reservoir decline. The NGLs component of liquids production decreased by 15mb/d, driven mainly by commercial changes in NGL processing contracts, natural reservoir decline and divestments. Gas production was lower (201mmcf/d) because of divestments and natural reservoir decline.

Development expenditure in the US (excluding midstream) during 2007 was $3,861 million, compared with $3,579 million in 2006 and $2,965 million in 2005. The annual increase is the result of various development projects in progress.

Our activities within the US take place in three main areas. Significant events during 2007 within each of these are indicated below.

Deepwater Gulf of Mexico

Deepwater Gulf of Mexico is our largest area of growth in the US. In 2007, our deepwater Gulf of Mexico liquids production was 196mb/d and gas production was 268mmcf/d.

Significant events were:

– The Atlantis platform (BP 56% and operator) was successfully commissioned and started producing oil and gas during the fourth quarter of 2007. Atlantis employs the deepest moored platform of its kind in the world and a separate semi-submersible drilling and construction rig. The versatile modular design of the platform provides potential to add wells to increase recovery.
– At Thunder Horse (BP 75% and operator), as a result of a metallurgical failure during pre-commissioning checks in 2006, the decision was taken to repair all at-risk subsea components. All relevant components have been removed from the sea floor and progress made in reinstalling the repaired equipment. In 2007, the platform s drilling rig was commissioned and its first well successfully drilled and completed. Thunder Horse is expected to start production by the end of 2008. Designed to process 250,000 barrels of oil per day and 200 million cubic feet per day of natural gas, Thunder Horse is expected to be the largest field in the Gulf of Mexico. The field will be supported by a network of 25 subsea wells.
– In November, BP started production from two multi-phase subsea pump stations in the King field (BP 100% and operator). At a depth of 1,700 metres and 15 miles away from the Marlin platform, this sets a double world record for both depth and distance. The two pumps are expected to enhance production from the King field by an average of 20% and to extend the production life of the field by five years through improved recovery.
– BP was awarded 88 blocks in the western Gulf of Mexico lease sale and 83 blocks in the central Gulf of Mexico lease sale.
– On 6 June 2007, a discovery was made with the Isabela well (BP 67% and operator), located on Mississippi Canyon Block 562 in approximately 2,000 metres of water about 150 miles south-east of New Orleans.
– During the second quarter, we increased our ownership in Horn Mountain to 100% as part of an asset exchange agreement with Occidental Petroleum Corporation (Occidental).
– In April 2007, BP disposed of its 80% interest in the Entrada field to Callon Petroleum Company for a total price of $190 million.

Lower 48 states

In the Lower 48 states (onshore), our 2007 natural gas production was 1,850mmcf/d, which was down 4% compared with 2006. Liquids production was 108mb/d, down 14% compared with 2006. The year-on-year decrease in production is mainly attributed to normal field decline and divestment activity. In 2007, we drilled approximately 400 wells as operator and continued to maintain a stable 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 222mboe/d in 2007.
– In the Gulf Coast and mid-continental basins (Kansas, Louisiana, Oklahoma and Texas) our assets produced 203mboe/d in 2007.

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:

– In January 2007, we announced our investment of up to $2.4 billion expected over 13 years in the coalbed methane field development project in the San Juan basin in Colorado. The project includes the drilling of more than 700 wells, nearly all from existing well sites, and the installation of associated field facilities.
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Drilling continued during 2007 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.

– Significant progress has been made on decommissioning the Gulf of Mexico Shelf hurricane-damaged platforms, which is on track for completion in 2010. This work has been carried out almost exclusively using a diverless access approach, significantly reducing exposure to safety issues associated with diving. Late in 2007, we signed an agreement with Wild Well Control, an affiliate of Superior Energy Services, to sell seven damaged platforms and 59 associated wells and consequentially to transfer the decommissioning liability to them. They will assume responsibility for plugging and abandonment of all wells, salvage and removal or reefing of the damaged platforms and related facilities, and restoration of all sites.
– In 2007, BP divested its non-core Permian assets as part of the asset exchange agreement with Occidental. In consideration, BP received the remaining one-third interest in the Horn Mountain field in the Gulf of Mexico and approximately $100 million cash.
– In the third quarter of 2007, we ceased operations at the Whitney Canyon gas plant located near Evanston, Wyoming. By doing this we expect to extend the economic life of the field by re-routing the natural gas processed at the Whitney Canyon gas plant to Chevron s Carter Creek gas plant. BP intends to continue to operate the 28 wells in the Whitney Canyon field and the inlet facility, as well as the nearby Painter Complex gas plant.

Alaska

In Alaska, BP net oil production in 2007 was 209mboe/d, a decrease of 7% from 2006, due to normal decline in the large mature fields, partially offset by lower downtime.

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. BP s 26.4% interest in Prudhoe Bay also includes a large undeveloped natural gas resource. Developing viscous oil production and unlocking large undeveloped heavy oil resources through the application of advanced technology are important parts of the Alaska business strategy.

Significant events in 2007 were:

– On 20 June 2007, the Prudhoe Bay field and the Trans Alaska Pipeline System (TAPS) celebrated the 30th anniversary of first production from the North Slope of Alaska. The original expectations for Prudhoe Bay were to drill 500 wells, produce for 20 years and recover 9 billion boe of hydrocarbon resources. After 30 years, more than 2,500 wells have been drilled, more than 11.5 billion boe have been recovered to date, and the field is expected to continue to produce for another 50 years or more. Prudhoe Bay production averaged 400mboe/d (gross) in 2007, with BP s net share being 102mboe/d. Overall, downtime during the year was consistent with plans for normal maintenance activity and there were no large unplanned production disruptions.

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- In 2007, we spent more than $250 million (BP net) in Alaska on a programme to upgrade or replace pipelines, increase inspection and corrosion monitoring, carry out preventative maintenance and repairs, expand capacity, and improve the efficiency of major facilities in all BP-operated fields.
- We have also made progress on the replacement of sections of oil transit lines in the Prudhoe Bay field, which for these transit lines has included adding pipeline pigging facilities to clean and inspect pipelines, direct corrosion inhibitor injection, new leak detection and corrosion monitoring systems. We aim to complete this activity in 2008.
- On 16 February 2007, BP temporarily shut down its Northstar production facility for 18 days to repair welds in the low pressure gas piping system. The facility was restarted on 6 March. The full-year impact of the production disruption resulting from this shutdown was more than offset by the beneficial impacts of an earlier-than-planned restart of the Milne Point K Pad pipeline replacement and strong reservoir performance throughout 2007 at Prudhoe Bay and Kuparuk.
- On 25 October 2007, BP Exploration Alaska (BPXA) entered into a plea agreement with the US Department of Justice (DOJ), which ended both federal and state government criminal investigations of BPXA on matters related to the March and August 2006 oil transit line spills in Alaska. On 29 November 2007, in accordance with the agreement, BPXA pleaded guilty to a misdemeanour violation of the US Federal Water Pollution Control Act. BPXA paid a $12 million (gross) fine and is subject to one-to-three years probation. BPXA also paid restitution of $4 million (gross) to the State of Alaska and paid another $4 million (gross) to the National Fish and Wildlife Foundation for Arctic environmental research. The DOJ and the State of Alaska have agreed not to bring any further criminal charges against BPXA in connection with the March and August 2006 spills.
- On 2 June 2007, the Alaska Gasline Inducement Act (AGIA) was passed into law. AGIA sets out the terms and conditions for application for the exclusive right to build a natural gas pipeline to transport North Slope gas to market. BP stated publicly that it cannot submit a conforming bid under AGIA because of, in its view, unresolved risks and uncertainties related to project costs, fiscal terms and pipeline tariffs. BP continues to develop and assess options for commercializing the major undeveloped gas resources on Alaska s North Slope.
- On 16 November 2007, the Alaska State Legislature passed a new petroleum production tax law, which replaced the Petroleum Production Tax legislation enacted in 2006. The new legislation increases production taxes and is effective retrospectively from 1 July 2007. The key terms of the new production tax law include a base oil tax rate of 25% on net profits, with progressive increases expected in the oil tax rate as the net margin increases above $30/bbl. The new production tax law will be governed by regulations to be defined and promulgated in 2008 by the Alaska State Department of Revenue.
- On 26 December 2007, the Alaska Superior Court issued a ruling reversing the 2006 decision by the Department of Natural Resources (DNR) to terminate the Point Thomson Unit and remanded the matter to the DNR to provide the leaseholders their constitutional due process rights, including the right to a hearing. Although the judge s decision found that the DNR s rejection of the latest plan of development (POD) was supported by substantial evidence, the ruling reinstated the leaseholders interests in the Point Thomson leases and unit, and instructed the DNR to consider good and diligent oil and gas . . . production practices in shaping an appropriate remedy for the rejected POD. The DNR is expected to call a hearing during the first quarter of 2008.
- On 3 October 2007, the Endicott field achieved its 20th year of production. Since start-up in 1987, Endicott has produced 500mmboe. During 2007, Endicott commenced a technology trial programme that is expected to progress BP s LoSal™ Enhanced Oil Recovery process from technology development to technology deployment. LoSal™ is a patented technology that utililizes geochemically specific waters to attack the larger remaining residual oils present after conventional waterflooding. To gain partner approval for a full-field deployment, an

  interwell programme has been started at Endicott. Results from this programme are expected in the second half of 2008 and are expected to lead to a full-field project commitment in 2009. The LoSal2™ technology has implications for many fields beyond BP s Alaska portfolio and the work at Endicott and in Alaska will be extrapolated to BP s global portfolio.
- On 3 January 2008, the US Minerals Management Service approved BP s development and production plan for the Liberty field. During 2007, $25 million was spent on pre-project planning for Liberty, including engineering, environmental studies and permit applications. Development plans for Liberty, which lies offshore to the east of the Endicott field, include ultra-extended reach wells to be drilled from pads at Endicott and processing Liberty oil production through existing Endicott facilities.

United Kingdom

We are the largest producer of oil, second largest producer of gas and the largest overall producer of hydrocarbons in the UK. In 2007, total liquids production was 201mb/d, a 20% decrease on 2006, and gas production was 768mmcf/d, an 18% decrease on 2006. This decrease in production was driven by natural decline and the unplanned shutdown of the Central Area Transmission System (CATS) pipeline. 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 $804 million in 2007, compared with $794 million in 2006 and $790 million in 2005.

Significant events in 2007 were:

- During the second quarter, we announced the decision not to proceed with the decarbonized fuel DF1 project in Scotland. This project was being led by BP, in partnership with Scottish and Southern Energy, and would have produced hydrogen as a decarbonized fuel for use in power generation, with the carbon dioxide (CO_2) gases being exported to the Miller oil reservoir in the North Sea for increased oil recovery and ultimate storage. Significant investment had been made in front- end engineering and design activity. Development of the project was originally planned to begin at the end of 2006 and required UK government support. In May, the UK government announced that it would not decide which carbon capture storage project to support until 2008 at the earliest. The timing of this decision did not fit with the DF1 project timeline, which was constrained by the maturity of the Miller oil field, and therefore the decision was taken not to proceed. The Miller field, which began production in 1992, has now ceased production and decommissioning activity is in the planning stage.
- We sanctioned the Dimlington Onshore Compression and Terminals Integration project, a $250-million investment in new gas compression facilities at the BP-operated Dimlington Terminal, which receives gas from fields in the southern North Sea. This new equipment is expected to reduce pipeline pressure between the offshore fields and the terminal, allowing the gas fields to increase production. BP expects remaining recoverable reserves in the West Sole and Amethyst fields to increase by around 30% as a result of this project.
- In October, we announced changes to the structure of the North Sea operations that are intended to simplify the organization and improve the efficiency of work processes in response to the challenges of the increasingly mature North Sea, where declining production and rapidly- rising costs have created business conditions that are not sustainable in the long term. The new structure will mean fewer organizational units and reduced management layers. This will allow consolidation of onshore non-technical support activities, leading to economies of scale and reduced complexity.

Rest of Europe

Development expenditure (excluding midstream) in the Rest of Europe was $443 million, compared with $214 million in 2006 and $188 million in 2005.

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Norway

In 2007, our total production in Norway was 56mboe/d, a 15% decrease on 2006. 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 2007. 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.
- In June, we announced the sanction of the combined Skarv and Idun development. This development is located in the Norwegian Sea approximately 200 kilometres west of Sandnessjøen. The fields will be developed using a Floating Production Storage and Offloading vessel (FPSO), subsea wells and an 80-kilometre gas export pipeline connecting to the Asgard Transport System.

Netherlands

On 1 February 2007, we completed the sale of our exploration and production and gas infrastructure business in the Netherlands to the Abu Dhabi National Energy Company, TAQA. This included onshore and offshore production assets and the onshore gas storage facility, Piek Gas Installatie, at Alkmaar.

Rest of World

Development expenditure in Rest of World (excluding midstream) was $5,045 million in 2007, compared with $4,522 million in 2006 and $3,735 million in 2005.

Rest of Americas

Canada

In Canada, our natural gas and liquids production was 52mboe/d in 2007, a decrease of 9% compared with 2006. The year-on-year decrease in production is mainly due to natural field decline.

In January 2008, we sanctioned the Noel Cadomin sweet gas project. A total of 130 wells are planned to be drilled with first production expected in 2009.

The Mist Mountain coalbed gas project is in the appraisal stage, which is expected to last for a number of years. The purpose of this stage is to assess the viability of coalbed gas production in British Columbia s Crowsnest coalfield by proving technologies and practices that will allow for the design of an environmentally sustainable commercial project. We are seeking British Columbia government approval to access public land for this project.

On 5 December 2007, BP announced it had signed a memorandum of understanding with Husky Energy Inc. to form an integrated North American oil sands business. The transaction is expected to be completed by the end of March 2008.

Trinidad

In Trinidad, natural gas production volumes increased by 7.5% to 2,434mmcf/d in 2007. The increase was delivered as a result of improved operating efficiency leading to increased throughput for Atlantic LNG Train 4, increased demand from the domestic market, full ramp up of the Cannonball field and the start-up of two new fields in 2007. Liquids production declined by 10mb/d (25%) to 30mb/d in 2007 from 40mb/d in 2006 as a result of the natural decline from high condensate fields.

The Mango and Cashima fields reached first gas on 17 November 2007 and 15 December 2007 respectively. Mango and Cashima were designed and built in Trinidad using a standardized design with 85% of fabrication hours and 65% of project management hours contributed by local Trinidad workers.

Venezuela

In Venezuela, due to the transition to the incorporated joint venture (IJV) entities in accordance with Venezuelan regulations that came into force in 2006, 2007 was the first full year of reduced interest. As a result of the aforementioned, and the OPEC quotas, our 2007 liquids production decreased by 10mb/d compared with 2006.

- On 26 June 2007, BP agreed to the migration of the Cerro Negro operations to an IJV without diluting its interest and signed a binding memorandum of understanding reflecting agreement to the significant terms and conditions for migration to, and operation of, the IJV. Signature of the final conversion contract, and finalization of the rest of the required procedures, is expected to take place in the first quarter of 2008.

Colombia

In Colombia, BP s net production averaged 46mboe/d. The reduction of 4mboe/d compared with 2006 is mainly due to natural field decline, partially compensated by additional gas sales. 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 September, BP was awarded two offshore blocks in the Caribbean that cover approximately 6,200 square kilometres. One block, RC4 (BP 35% and operator), will be a joint venture with state-owned Ecopetrol and Petrobras, while BP will have sole rights to develop the other, RC5 (BP 100% and operator).

In December 2006, the Colombian Congress passed new legislation to reduce corporate income taxes from 35% to 34% in 2007 and 33% in 2008.

After months of negotiations with Ecopetrol, agreement around extension of the current association contracts was not reached. However, new commercial agreements are in the final stages of negotiation to allow partners to access new investment opportunities.

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 2007, total PAE gross production of 264mboe/d represented an increase of 1% over 2006. This increase came from the continued focus on drilling in Golfo San Jorge in Argentina. 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.

On 27 April, PAE entered into an agreement with the Argentine province of Chubut, which provides for the concession term extension and includes certain investment commitments related to exploration and production on the Cerro Dragón block, located in Golfo San Jorge basin. On 25 June, PAE signed a similar agreement with Santa Cruz province. These are the first agreements entered into to extend the term of concessions in Argentina, and were formalized under the framework established by a law recently passed by the Argentine Congress that will allow PAE to undertake long-term projects.

On 13 July, PAE signed a loan agreement with the International Finance Corporation (IFC) for the amount of $550 million. This loan will be used to finance a programme of capital investment in the Cerro Dragón block in Argentina. The last tranche will mature in April 2018.

On 2 May, following notarization, the new agreements entered into by PAE and other oil and gas companies with Yacimientos Petroliferos Fiscales Bolivianos (YPFB) in Bolivia in November 2006 became effective. These agreements are intended to run until 31 December 2026 and establish the commitment assumed by each of the companies to supply the Bolivian domestic gas market. YPFB will be responsible for marketing all hydrocarbons produced in Bolivia and for determining the terms of relevant gas sales contracts. Along with these changes, the volumes that Chaco (an exploration and production company operated in Bolivia owned 50% by PAE and 50% by YPFB, 30% BP net) is allowed to export have been significantly increased resulting in higher overall gas sales realizations for Chaco.

In a continuation of changes made to the export tax since its inception in 2002, the Argentine government issued a resolution in November 2007 increasing the export tax rate on oil when the international crude oil price is US$60.9/bbl or higher.

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Africa

Algeria

BP, through its joint operatorships of the In Salah Gas (33.15%) and In Amenas (12.50%) projects, supplied 83bcf (BP net) of gas to markets in Algeria and southern Europe during 2007, an increase of 33% from 2006 due to the ramp up of In Amenas during 2007. The CO_2 capture system, part of the In Salah project, is one of the world s largest CO_2 capture projects.

Angola

In Angola, BP net production in 2007 was 139mboe/d, an increase of 5% from 2006 due to the start up of the Greater Plutonio, Marimba and Rosa fields, and the ramp up of Dalia, more than offsetting PSA changes in the Kizomba A, Kizomba B and Girassol fields.

The first lifting from the Dalia field (BP 16.67%) was achieved during the first quarter of 2007, with gross field production ramping up to 245mb/d by the end of 2007. The Dalia field was discovered in 1997. It entered project execution phase in the first half of 2003 and production began on 13 December 2006.

During the second quarter, the Rosa project (BP 16.67%) achieved first production. Discovered in January 1998, some 135 kilometres off the coast of Angola in water depths of approximately 1,350 metres, the Rosa field is located 15 kilometres away from the Girassol FPSO to which it is tied back. It is the first deepwater field of this size to be tied back to such a remote installation and in such water depths. Rosa is expected to maintain the FPSO s production capacity above250mb/d until early in the next decade.

Oil production at the Greater Plutonio offshore development area in Block 18 began in October 2007. The five fields making up the Greater Plutonio development were discovered between 1999 and 2001 in water depths of up to 1,450 metres and it is the first BP-operated asset in Angola (BP 50% and operator). The development utilizes an FPSO connected to the wells by a large subsea system. The subsea system is expected to ultimately encompass 43 wells and the longest single-riser tower system of its kind in the world. Many components of the project were constructed in Angola including the world s largest Caternary Anchor Leg Mooring (CALM) buoy.

In October, production commenced from the Marimba North project (BP 26.67%), in Block 15. The field is in approximately 1,300 metres of water more than 145 kilometres off the coast of Angola. The Marimba North project is a tie-back to the Kizomba A development. The Marimba North production and control facilities have been integrated with the existing Kizomba A development to effectively and cost efficiently utilize the existing field facilities. Start-up of the field was achieved safely without any production impact to the Kizomba A operations.

In the ultra deepwater Block 31 there were three exploration successes, Miranda, Cordelia and Portia, bringing the total for Block 31 to 15. The Miranda well is located in a water depth of approximately 2,436 metres, some 375 kilometres northwest of Luanda. The Cordelia well is located in a water depth of approximately 2,308 metres, some 371 kilometres northwest of Luanda. The Portia well is located in a water depth of approximately 2,012 metres, some 386 kilometres northwest of Luanda.

In August, the Pazflor Project in Angola Block 17 (BP 16.67%) was sanctioned. Pazflor will be a standalone FPSO development, the third major production hub in Block 17, and is expected to deliver first oil in 2011. The development will be based on a new-build FPSO with subsea wells, rigid flowlines and subsea processing.

In January 2008, production began at the Mondo field (BP 26.67%) in Block 15. Located in water depths of approximately 800 metres, the field utilizes an FPSO and has a total of 36 subsea wells.

Egypt

In Egypt, BP net production was 97mboe/d, an increase of 10% from 88mboe/d in 2006. This increase was mainly due to an increase in the number of producing wells and the benefit of full-year production from producing wells drilled in 2006.

In Egypt, the Gulf of Suez Petroleum Company (GUPCO) (BP 50%), a joint venture operating company between BP and the Egyptian General Petroleum Corporation (EGPC), 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 a total of more than 40 fields.

Progress continued on the Saqqara field (BP 100%) development project, with first production expected in 2008.

Progress continued on the Egypt Gas Phase 1 (Taurt) (BP 50%) development project, with first production expected in 2008.
In January 2007, BP drilled a successful well, Giza North-1, in the North Alexandria concession (BP 60% and operator) held by BP, RWE DEA and EGPC/The Egyptian Natural Gas Holding Company (EGAS). The Giza North-1 was drilled in 668 metres of water, some 56 kilometres offshore in the Pliocene formation where BP has made three previous discoveries.
In May 2007, BP drilled a successful well, Taurus Deep, in the North Alexandria A Concession (BP 60% and operator) held by BP, RWE DEA and EGPC. The Taurus Deep well was drilled in approximately 400 metres of water, some 70 kilometres offshore, and is in the Middle Miocene formation.
In January 2008, BP finished drilling a successful well, Satis-1, in the North El Burg offshore concession (BP 50% and operator) held by BP, IEOC and EGAS. The Satis-1 well was drilled in approximately 90 metres of water, some 50 kilometres offshore, and is in the Oligocene formation.
In December 2007, BP had first production from the Denise field where it holds a 50% interest.

Libya

In May, BP and its partner, the Libyan Investment Corporation (LIC) signed a major exploration and production agreement with Libya sNational Oil Company. The initial exploration commitment is set at a minimum of $900 million with significant appraisal and development expenditures dependent on exploration success. BP and the LIC will explore over 53,000 square kilometres of the onshore Ghadames and offshore frontier Sirt basins. Successful exploration could lead to the drilling of around 20 appraisal wells. The agreement was ratified by the Libyan General People s Council on 23 December.

Asia Pacific

Indonesia

BP produces crude oil and supplies natural gas to the island of Java through its holding in the Offshore Northwest Java PSA (BP 46%). In 2007, BP net production was 39mboe/d, a decrease of 8.8% from 43mboe/d in 2006 as a result of a higher-than-forecasted base decline, unplanned losses and the impact of higher realizations on the PSA.
During 2007, development 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 commercial delivery is expected in early 2009.

Vietnam

BP participates in one of the country s largest projects with foreigninvestment, the Nam Con Son gas project. This is an integrated resource and infrastructure project, including offshore gas production, a pipeline transportation system and power plant. In 2007, BP net natural gas production was 82mmcf/d gross, a decrease of 15% over 2006. This decrease was mainly due to higher supply from another gas field brought onstream in late 2006. 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 33.3%).

China

In 2007, natural gas production was 85mmcf/d BP net, a decrease of 17% over 2006. This decrease was mainly due to the closure of a Rate Acceleration Agreement with a key customer at the end of 2006.

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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 selectricity. 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.

In March, the National People s Congress reduced the rate ofcorporation tax from 33% to 25% with effect from 1 January 2008.

Australia

In Australia, BP net gas production in 2007 was 376mmcf/d, an increase of 3.3% from 2006 due to increased domestic gas demand in Western Australia. BP net liquids production at 34mb/d remained unchanged from 2006.

BP is one of seven partners in the North West Shelf (NWS) venture. Six partners (including BP) hold an equal 16.7% interest in the infrastructure and oil reserves and an equal 15.8% interest in the gas and condensate reserves with a seventh partner owning the remaining 5.32% of gas and condensate reserves. The operation covers offshore production platforms, an FPSO, trunklines and onshore gas processing plants. The NWS venture is currently the principal supplier to the domestic market in Western Australia. During 2007, progress continued on the construction of a fifth LNG train (4.7 million tonnes per year design capacity), with first throughput expected in the second half of 2008.

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 inOAO TNK-BP Holding. Other assets include the BP-branded retail sites in Moscow and the Moscow region and interests in OAO Rusia Petroleum and the OAO Slavneft group. The workforce comprises more than 60,000 people.

BP s investment in TNK-BP is held by the Exploration and Productionsegment and the results of TNK-BP are accounted for under the equity method in this segment.

TNK-BP has proved reserves of 6.9 billion barrels of oil equivalent (including its 49.9% equity share of Slavneft), of which 4.5 billion are developed. In 2007, TNK-BP s average liquids production was1.7mmboe/d, a decrease of just over 5% compared with 2006, reflecting the disposal of the Udmurt asset in 2006. The production base is largely centred in West Siberia (Samotlor, Nyagan and Megion), which contributes about 1.2mmboe/d, together with Volga Urals (Orenburg) contributing some 0.4mmboe/d. About 44% of total oil production is currently exported as crude oil and 19% as refined product.

Downstream, TNK-BP has interests in six refineries in Russia and the Ukraine (including Ryazan and Lisichansk and Slavneft s Yaroslavl refinery), with throughput of approximately 35 million tonnes per year. During December 2007, TNK-BP agreed to purchase additional retail and other downstream assets in Russia and the Ukraine from a number of small companies with completion due in 2008. TNK-BP supplies approximately 1,600 branded filling stations in Russia and the Ukraine and, with the additional sites, is expected to have more than 20% market share of the Moscow retail market.

In January 2007, TNK-BP announced the purchase of Occidental s50% interest in the West Siberian joint venture, Vanyoganneft, for $485 million. The transaction closed during the first quarter of 2007 and TNK-BP now owns 100% of the Vanyoganneft asset.

On 22 June, BP and TNK-BP signed heads of terms to create strategic business alliances with OAO Gazprom. Under the terms of this agreement, TNK-BP agreed to sell to Gazprom its 62.89% stake in OAO Rusia Petroleum, the company that owns the licence for the Kovykta gas condensate field in East Siberia and its 50% interest in East Siberia Gas Company (ESGCo). BP and TNK-BP have an option to repurchase on market terms up to 25% + 1 share in OAO Rusia Petroleum and up to 25% of ESGCo in the event that a strategic business alliance is subsequently established with OAO Gazprom.

In November 2006, following a review of the results of an inspection by the licensing authorities that had resulted in a request for the revocation of the two licences held by TNK-BP subsidiary Rospan International, an agreed rectification plan was put in place. All the Rospan licence compliance issues arising from the inspection by the licensing authorities in 2006 are now substantially resolved.

Sakhalin

BP participates in the KV licence area in offshore Sakhalin where it conducts exploration activities through Elvaryneftegas (BP 49%), an equity-accounted joint venture with Rosneft. Two discoveries have been made to date in the KV licence area. BP also participates in joint operations in two licence areas with Rosneft in East and West Shmidt (BP 49%).

Exploratory drilling continued in 2007 with the drilling of two wells in the West Shmidt licence area. Both wells were found to be dry and, as a result, BP wrote off all expenditures related to the West Shmidt licence area.

The 2008 work programme for the Sakhalin licence includes seismic re-processing in the East Shmidt licence area and a 2D seismic acquisition programme in the KV licence area. No drilling is planned for 2008.

Other

Azerbaijan

In Azerbaijan, BP net production in 2007 was 218mboe/d, an increase of 50% from 2006 due to the ramping up of three Azeri oil producing platforms and the Shah Deniz condensate gas platform commencing production in 2007.

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 3 of the project, which will develop the deepwater Gunashli area of ACG, remains on schedule to begin production in 2008 with platform topsides having been completed in September 2007.

BP is the operator of Shah Deniz (BP 25.5%), which is in the Azerbaijan sector of the Caspian Sea and will deliver gas to markets in Azerbaijan, Georgia and Turkey. First gas to Turkey was achieved in July 2007. Production from the field is expected to continue to ramp up as further wells are brought onstream. Plateau production from Stage 1 is expected to be 6.9 billion cubic metres of gas per annum and approximately 30,000 barrels of condensate per day.

In November, we announced a further major new gas-condensate discovery in the Shah Deniz field in the Caspian Sea. The SDX-04 exploration and appraisal well, some 70 kilometres south-east of Baku, discovered a new deeper structure below the currently producing reservoir. Drilled to a Caspian-record depth of more than 7,300 metres in the south-western part of Shah Deniz, the well encountered gas condensate in the main target horizons extending the field to the south. The well also discovered a new high pressure reservoir in a deeper structure.

Middle East and south Asia

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 2007, BP s share of production in Abu Dhabi was 192mb/d, down 3% from 2006 as a result of a major planned maintenance shutdown in the offshore concession in the fourth quarter of 2007.

In Pakistan, BP doubled its equity in the onshore Badin asset (BP 84%) as part of an international asset exchange with Occidental. As a result of this transaction, BP net oil production in 2007 was 6.3mboe/d, an increase of 24% from 2006, and BP net gas production was 122mmcf/d, an increase of 39.4% from 2006.

In the third quarter of 2007, BP signed a farm-in agreement with Petroleum Exploration (Private) Limited to obtain a 33% participating

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interest in Blocks P, J and O in the deepwater Indus basin offshore Pakistan.

In January 2007, BP signed a major PSA with the Sultanate of Oman to appraise sour tight gas reservoirs in Block 61. Major contracts were awarded in November with 3D seismic planned to commence in the first quarter of 2008 and drilling in the fourth quarter of 2008. The full appraisal programme is expected to take up to six years.

In September, BP signed a memorandum of understanding with Oil and Natural Gas Corporation Ltd of India regarding co-operation in coalbed methane and deepwater offshore exploration.

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. 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. Revenue is earned on pipelines through charging tariffs.

BP s onshore US crude oil and product pipelines and related transportation assets are included under Refining and Marketing (see page 26).

Assets and activity during 2007 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 738mb/d during 2007.

Work on the strategic reconfiguration project to upgrade and automate four pump stations continued to progress during 2007. This project will install electrically-driven pumps at four critical pump stations, combined with increased automation and upgraded control systems. Two of the reconfigured pump stations came online during 2007, one in the first quarter and another in the fourth quarter. The remaining two reconfigured pump stations are expected to come online sequentially in 2009 and 2010.

There are a number of unresolved challenges lodged by instate refiners, Tesoro and Flint Hills, against BP and the other TAPS carriers, regarding intrastate tariffs charged for shipping oil through TAPS. These challenges were filed between 1986 and 2003 with the Regulatory Commission of Alaska (RCA). In 2002, the RCA determined that TAPS transportation rates charged since the beginning of 1997 have been excessive and that refunds should be paid. Proceedings relating to transportation charges covering the period between 1986 and mid-2003, including an appeal by BP and the other TAPS carriers of the RCA s 2002 determination, are progressing through the Alaska judicial system. No significant refunds have been paid pending the resolution of these matters in the courts. In the interim, the RCA has imposed intrastate rates effective from 1 July 2003 that are consistent with its 2002 order. Intrastate transport makes up roughly 7% of total TAPS throughput.

Tariffs for interstate and intrastate transportation on TAPS are calculated using the RCA and Federal Energy Regulatory Commission (FERC)-accepted TAPS Settlement Methodology (TSM) entered into with the State of Alaska in 1985. The State of Alaska, Anadarko and Tesoro have challenged BP s and the other TAPS carriers 2005, 2006 and 2007 interstate tariffs with the FERC, and the State of Alaska and Anadarko have challenged BP s and the other TAPS carriers 2008 tariffs with the FERC. The challengers assert that the interstate transportation rates charged by BP (in accordance with the TSM) and the other TAPS carriers, are excessive and discriminatory and in violation of the Interstate Commerce Act, and that costs related to the TAPS Strategic Reconfiguration project were imprudently incurred.

That portion of the challenges filed by the State, Anadarko and Tesoro relating to the TAPS Strategic Reconfiguration project costs, together with all aspects of the 2007 challenges, are being held in abeyance by the FERC until its decision on 2005 and 2006 rates is issued. There have been no proceedings in the recently filed challenges to BP s 2008 FERC tariff. The FERC s hearings on the consolidated proceedings commenced in October 2006 and concluded in January 2007. On 17 May 2007, a FERC Administrative Law Judge issued an Initial Decision as to 2005 and 2006 rates. This Initial Decision, which was adverse to BP and the other TAPS carriers, is now under consideration by the FERC Commissioners, who will issue the decision of the FERC. Pending the decision of the FERC Commissioners, BP is continuing to collect its TSM-based interstate tariffs; however, our tariffs are subject to refund depending on the decision of the FERC. 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 1 million barrels per day, with average throughput in 2007 at 653mb/d. The tie-in of the Buzzard field was completed, with first Buzzard production flowing through the system in January 2007. The Greater Kittiwake Area also joined the system in late 2007.

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 1,700mmcf/d to a natural gas terminal at Teesside in north-east England. CATS offers natural gas transportation and processing services. In 2007, throughput was 778mmcf/d (gross), 230mmcf/d (net). During September, the CATS pipeline resumed operation after divers installed a metal sleeve at the location where a large vessel had dragged its anchor causing damage to the pipeline. The pipeline was shutdown for 10 weeks resulting in a loss of production of 11mboe/d for the year.

BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe oil and gas terminal in Shetland.

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 has a capacity of 1mmboe/d from the BP-operated ACG oil field in the Caspian Sea to the eastern Mediterranean port of Ceyhan. In the first quarter of 2007, the BTC pipeline celebrated the loading of its 100-millionth barrel at the Ceyhan terminal and loaded its 250th tanker in October 2007.

Transportation of first gas to Turkey from Shah Deniz in Azerbaijan via the South Caucasus Pipeline was achieved in July 2007. BP is technical 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 2007, CPC total throughput reached 33.03 million tonnes. During 2007, shareholders agreed to restore the profitability of CPC by increasing the CPC tariff and cutting interest rates on shareholder loans. Negotiations continued between the CPC shareholders on an expansion plan and a plan for financial restructuring. 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. 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,

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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 and 15.8% gas and condensate reserves).

Assets and activity during 2007 included:

– In Trinidad, the Atlantic LNG Train 4 (BP 37.8%) is the largest producing LNG train in the world and is designed to produce 5.2 million tonnes (253,000mmcf) per year of LNG. BP expects to continue to supply at least two-thirds of the gas to the train. The Atlantic LNG Trains 2, 3, and 4 facilities are operated under a tolling arrangement, with the equity owners retaining ownership of their respective gas. The LNG is 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 (310,000mmcf) of LNG per year.
– 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 14% of the total gas feed to Bontang, one of the world s largest LNG plants. The Bontang plant produced 18.4 million tonnes (831,000mmcf) of LNG in 2007, compared with 19.5 million tonnes in 2006.
– 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 2007, construction continued on two trains, with commercial delivery planned in early 2009. Tangguh will be the third LNG centre in Indonesia, with an initial capacity of 7.6 million tonnes (388,000mmcf) per year. Tangguh has signed sales contracts for delivery to China, Korea and North America s west coast.
– In Australia, we are one of seven partners in the NWS venture. Six partners (including BP) hold an equal 16.7% interest in the infrastructure and oil reserves and an equal 15.78% interest in the gas and condensate reserves, with a seventh partner owning the remaining 5.32% of gas and condensate reserves. The joint venture operation covers offshore production platforms, an FPSO, trunklines, onshore gas and LNG processing plants and LNG carriers. Construction continued during 2007 on a fifth LNG train that is expected to process 4.7 million tonnes of LNG per year and is expected to increase the plant s capacity to 16.6 million tonnes per year. The train is expected to be commissioned during the second half of 2008. NWS produced 1.96 million tonnes (102,000mmcf) of LNG, equal to 2006 production.
– We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2007 supplied 5.6 million tonnes (272,710mmcf) of LNG, up 4.2% on 2006.
– BP has a 13.6% share in the Angola LNG project, which is expected to receive approximately one billion cubic feet of associated gas per day from offshore producing blocks and produce 5.2 million tonnes per year of LNG, as well as related gas liquids products, with first LNG expected in 2012. With the completion of the necessary agreements and the approval of the Angolan government, the project investors have authorized Angola LNG Limited to proceed with the construction and implementation of the project.

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Refining and Marketing

Our Refining and Marketing business is responsible for the supply and trading, refining, manufacturing, 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 manufacture and market our products across Australasia and in parts of Asia, Africa and Central and South America.

Key statistics

			$ million
	2007	2006	2005
Sales and other operating revenues for continuing operations	**250,866**	232,855	213,326
Profit before interest and tax from continuing operations[a]	**6,072**	5,541	6,426
Total assets	**95,691**	80,964	77,485
Capital expenditure and acquisitions	**5,586**	3,144	2,860
			$ per barrel
Global Indicator Refining Margin[b]	**9.94**	8.39	8.60

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

[b] The Global Indicator Refining Margin (GIM) is the average of regional industry indicator margins, which we weight for BP s crude refining capacity in each region. Each regional indicator margin is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity. The refining margins are industry-specific rather than BP-specific measures, which we believe are useful to investors in analyzing 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 key components of sales and other operating revenues are explained in more detail below.

			$ million
	2007	2006	2005
Sale of crude oil through spot and term contracts	**43,004**	38,577	36,992
Marketing, spot and term sales of refined products	**194,979**	177,995	155,098
Other sales including non-oil and to other segments	**12,883**	16,283	21,236
	250,866	232,855	213,326
			thousand barrels per day
Sale of crude oil through spot and term contracts	**1,885**	2,110	2,464
Marketing, spot and term sales of refined products	**5,624**	5,801	5,888

The Refining and Marketing segment includes Refining, Fuels Marketing, Lubricants and Aromatics & Acetyls. Our strategy is to continue our focused investment in key assets and market positions with an increased focus on process safety, integrity and reliability following the operational issues at the Texas City and Whiting refineries. We aim to improve the quality and capability of our manufacturing portfolio. During 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 most of our refineries. In 2007, we completed a major upgrade to the olefin cracker at the Gelsenkirchen refinery in Germany and an upgrade of an existing diesel hydrotreater at the Rotterdam refinery in the Netherlands. During the next five years, we expect to upgrade further our refining portfolio through the construction of a new coker at the Castellón refinery, a planned and announced investment in the Whiting refinery to increase its ability to process Canadian heavy crude, upgrades to diesel and gasoline desulphurization capability at the Rotterdam refinery in the Netherlands, the installation of modern naphtha reforming

technology at several refineries globally, the site reconfiguration and installation of a new hydrocracker at the Bayernoil refinery in Germany and the full recommissioning of the Texas City refinery in the US.

Our marketing businesses generate customer value by providing quality products and offers. Our retail network 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. Marketing also includes the Aromatics & Acetyls business, which maintains world-class manufacturing positions globally, with an emphasis on the Asian market, particularly in China. At the end of 2007, the business increased its capacity in China by successfully commencing the commissioning of a new 900 thousand tonnes per annum (ktepa) worldscale purified terephthalic acid (PTA) plant at Zhuhai.

The segment manages a portfolio of assets that we believe are competitively advantaged across the chain of downstream activities. Such advantage may derive from several factors, including location (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.

During 2007, significant events were:

– BP continued recommissioning the Texas City refinery in the US. By the end of 2007, we had successfully recommissioned the three desulphurization and upgrading units necessary to allow restart of the remaining crude distillation capacity. The final sour crude unit is mechanically complete and is expected to be fully operational during the first quarter of 2008. By mid-2008, we expect most of the economic capability at the Texas City refinery to have been restored.
– On 23 March 2007, a fire at the Whiting refinery in the US caused damage to the hydrogen compressors and limited the site s throughput and ability to make low-sulphur gasoline or diesel fuel from sour crude oil. By the end of 2007, the Whiting refinery had recommenced sour crude processing and available distillation capacity exceeded 300,000b/d.
– On 1 February 2007, BP announced it had selected the University of California Berkeley, and its partners the University of Illinois at Urbana-Champaign and the Lawrence Berkeley National Laboratory, to join in the previously announced $500-million research programme to explore how bioscience can be used to increase energy production and reduce the impact of energy consumption on the environment.
– On 31 March 2007, BP completed its acquisition of Chevron s Netherlands manufacturing company, Texaco Raffinaderij Pernis B.V., for $1.1 billion. The acquisition included Chevron s 31% interest in the Rotterdam (Nerefco) refinery.
– On 31 May 2007, BP completed the sale of its Coryton refinery in the UK to Petroplus Holdings AG for consideration of $1.4 billion, plus working capital.
– On 26 June 2007, BP, Associated British Foods and DuPont announced an investment of $400 million in the construction of a world-scale bioethanol plant with expected annual production capacity of some 420 million litres from wheat feedstock, expected to be commissioned in late 2009.
– On 29 June 2007, BP announced a joint venture with D1 Oils plc, a UK-based global producer of biodiesel, for the development of jatropha as a new energy crop.
– On 15 November 2007, BP announced that it would sell all of its company-owned and company-operated convenience sites in the US. The majority of sites will be sold to franchisees with the remaining sites sold to dealers and large distributors (jobbers). The sale of the sites is expected to be completed by the end of 2009. The sites will continue to market BP-branded fuels in the eastern US and ARCO- branded fuels in the western US. The franchise agreement is for 20

years and requires sites to be supplied with BP or ARCO-branded fuels for the term of the contract.

– In December 2007, the second PTA plant at the BP Zhuhai Chemical Company Limited site in Guangdong province, China, successfully commenced commissioning.
– On 5 December 2007, BP announced it had agreed to create an integrated North American oil sands business with Husky Energy Inc., by means of two separate joint ventures. In one, BP will take a 50% interest in Husky Energy s Sunrise field in Alberta, Canada, while in the other, Husky will take a 50% interest in BP s Toledo refinery, between them forming an integrated North American oil sands business. As part of this agreement, and subject to negotiation of final agreements and obtaining the necessary approvals and permits, the Toledo refinery is intended to be expanded to process approximately 170mb/d of heavy oil and bitumen by 2015.
– BP continued to progress the planning for the previously mentioned investment in Canadian heavy crude oil processing capability at its Whiting refinery. This project is expected to reposition Whiting competitively as a top-tier refinery by increasing its Canadian heavy crude processing capability by 260mb/d and modernizing it with equipment of significant size and scale.
– In mid-January 2008, BP and Sinopec signed a memorandum of understanding to add a new 650ktepa acetic acid plant at their YARACO joint venture in Chongqing, upstream Yangtze River, south- west China. This world-scale acetic acid plant, using BP s leading Cativa™ technology, is expected to come onstream in 2011.

Resegmentation in 2008

With effect from 1 January 2008:

– The Emerging Consumers Marketing Unit was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
– The Biofuels business was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
– The Shipping business was transferred from Refining and Marketing to Other businesses and corporate.

Texas City refinery

On 23 March 2005, an explosion and fire at the Texas City refinery occurred in the isomerization unit as the unit was starting up after routine planned maintenance. The incident claimed the lives of 15 workers and injured many others.

Throughout 2007, BP continued to implement the process safety enhancement programme it initiated in response to the March 2005 incident, which included policies, practices and activities to address a number of the factors that contributed to the incident, including the siting of occupied portable buildings and the removal of blow-down stacks handling heavier-than-air light hydrocarbons. BP also implemented, across its US refining system and at other facilities worldwide, a number of additional actions relating to safety and operations, atmospheric relief valves, operating procedures and training, control of work systems, and process safety culture and leadership. In the US, BP has committed to increase spending to an average of $1.7 billion per year through 2010 to improve the integrity and reliability of its refining assets and has created an operations advisory board to assist BP America Inc. s management in monitoring and assessing BP s US operations.

Governmental investigations

In 2007, BP continued its co-operation with the governmental entities investigating the Texas City incident, including the US Department of Justice (DOJ), the US Environmental Protection Agency (EPA), the US Occupational Safety and Health Administration (OSHA), the US Chemical Safety and Hazard Investigation Board (CSB) and the Texas Commission on Environmental Quality (TCEQ). On 25 October 2007, the DOJ announced that it had entered into a criminal plea agreement with BP Products North America Inc. (BP Products) related to the March 2005 explosion and fire. On 4 February 2008, BP Products pleaded guilty in

federal court, pursuant to the plea agreement, to one felony violation of the risk management planning regulations promulgated under the US federal Clean Air Act. At the plea hearing, the court advised that it would take the matter under review and decide whether to accept or reject the plea. If the court accepts the agreement, BP Products will pay a $50 million criminal fine and serve three years probation. Separately, BP Products reached a civil settlement in principle with the EPA and the DOJ related to issues identified in EPA inspections that followed the March 2005 incident. BP expects the settlement to be finalized in 2008.

The CSB issued its final report on the Texas City incident in March 2007. Although BP disagreed with some of the findings and conclusions in the report, BP gave full and careful consideration to the CSB s recommendations and committed to implement actions in alignment with each of the CSB s recommendations. BP has many activities under way, including activities around reporting health and safety and operational incidents, and incident investigation, in response to the recommendations of the BP US Refineries Independent Safety Review Panel (the panel) (see below) to improve process safety, both at Texas City (as recommended by the CSB) and across the group. BP and the CSB continue to discuss BP s responses with the objective of the

CSB agreeing to close out its recommendations.

Civil tort actions

A large number of civil claims have arisen from the Texas City incident, for which BP has set aside $2,125 million in aggregate. Thus far, BP has reached more than 2,000 settlements in respect of all the fatalities and many of the personal injury claims arising from the incident. A number of claims remain to be resolved.

See Legal proceedings on page 82 for further information.

Report of the BP US Refineries Independent Safety Review Panel

The panel was established by BP in 2005 at the recommendation of the CSB to assess the effectiveness of safety management systems at BP s five US refineries and the corporate safety culture. The panel, which was chaired by the former US Secretary of State, James A Baker, III, issued its report in January 2007. Although the panel did not specifically investigate the Texas City incident or seek to determine its causes, the report contained observations applicable to all of BP s US refineries, including Texas City. The panel s report acknowledged the measures taken by BP since the Texas City incident, including dedicating significant resources and personnel in an effort to improve the process safety performance of BP s US refineries. The panel s report can be found at *www.bp.com/bakerpanelreport*. BP accepted the 10 recommendations of the panel and began (or, in some cases, continued) improvement activities addressing a number of the recommendations, including consistent implementation of risk identification tools, improvements in incident reporting and investigation systems, and enhancements to the group s reporting and monitoring programmes. At the panel s recommendation, in May 2007, the BP board also appointed an independent expert to monitor progress in implementing the panel s recommendations to improve safety performance at BP s US refineries. The independent expert, L. Duane Wilson, who was a member of the panel, reports directly to the BP board s safety, ethics and environment assurance committee.

In addition to these direct responses to the panel s recommendations, BP has also taken a number of additional steps that are in line with the spirit of the panel s report. BP has developed a comprehensive programme to implement the panel s recommendations within its US refining system and to share learnings from the panel throughout the refining system. This programme makes use of the newly developed group-wide operating management system (OMS). Each refinery is creating an implementation plan to reduce process safety risk on a continuous improvement basis and to provide for the future implementation of OMS. In 2007, BP also reached an agreement in principle with the United Steel Workers Union to work jointly on a 10-point plan to improve process safety across the four represented US refineries.

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Other regulatory actions

OSHA

In January 2007, OSHA began a new inspection at the Texas City refinery focusing on relief valves, flare capacity and other process safety issues at one of the catalytic cracking units. OSHA issued citations in July 2007 with a total penalty of $92,000. Separately, OSHA has questioned whether the process safety management expert (AcuTech), appointed in connection with the September 2005 settlement agreement with OSHA, adequately reviewed equipment pressure relief valve issues. BP has entered into negotiations to resolve the cracking unit citations and, in the interim, has agreed to the assignment of this case to a settlement judge. On 16 January 2008, BP addressed OSHA s concerns regarding the September 2005 settlement agreement by agreeing to retain an expert relief system consultant to audit individual hydrocarbon relief devices and flare systems on two units and to share the consultant s findings with OSHA.

In September 2007, BP and OSHA entered into a settlement agreement related to citations stemming from OSHA s inspection of the Toledo refinery in 2005. OSHA granted final approval of the settlement in November 2007.

BP is attempting to negotiate a settlement relating to citations, with a total penalty of $384,000, stemming from Indiana OSHA s inspection of the Whiting refinery in 2006, but the case is still pending. In August 2007, Indiana OSHA initiated a separate inspection relating to an April 2007 incident that resulted in a crude unit shutdown and the release of 40,000 pounds of hydrocarbons. On 30 January 2008, OSHA issued a safety order that alleges two violations, for a total penalty of $10,000.

OSHA conducted an inspection related to the death of a contract diver at the Cherry Point refinery in August 2007. OSHA concluded its

investigation in October 2007 and informed BP that no citations would be issued to it.

In January 2008, an employee died at Texas City refinery. This incident is currently being investigated by BP, OSHA and the CSB.

EPA

The EPA has asked the DOJ to file a civil lawsuit based on inspections it conducted at the Whiting, Toledo, Cherry Point and Carson refineries following the March 2005 Texas City incident. BP Products and the EPA/ DOJ have begun settlement negotiations in an effort to avoid litigation of the matter.

Refining

The group 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 lower-cost feedstocks in line with the demand of the region. Strategic investments in our refineries are focused on securing the safety and reliability of our assets while improving our competitive position. In addition, we continue to invest to develop 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 2007.

			thousand barrels per day	
			Crude distillation capacities[a]	
	Refinery	Group interest[b] %	Total	BP share
Rest of Europe				
Germany	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	Rotterdam*	100.0%	392	392
Spain	Castellón*	100.0%	110	110
Total Rest of Europe			1,661	866
US				
California	Carson*	100.0%	266	266
Washington	Cherry Point*	100.0%	234	234
Indiana	Whiting*	100.0%	405	405
Ohio	Toledo*[c]	100.0%	155	155
Texas	Texas City*	100.0%	475	475
Total US			1,535	1,535
Rest of World				
Australia	Bulwer*	100.0%	101	101
	Kwinana*	100.0%	137	137
New Zealand	Whangerei	23.7%	102	24
Kenya	Mombasa[d]	17.1%	94	16
South Africa	Durban	50.0%	180	90
Total Rest of World			614	368
Total			3,810	2,769

* 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.

c Subject to negotiation of final agreements and obtaining the necessary approval and permits, Husky Energy will take a 50% interest in BP s Toledo refinery as described on page 27.

d On 15 January 2008, it was announced that Essar Energy Overseas Ltd, a subsidiary of Essar Oil Limited, had entered into an agreement to acquire 50% of Kenya Petroleum Refineries Ltd. Subject to certain conditions, the acquisition, which includes all of BP s interest, is expected to complete in early 2008.

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]	**2007**	2006	2005
UK	**67**	165	180
Rest of Europe	**691**	648	667
US	**1,064**	1,110	1,255
Rest of World	**305**	275	297
Total	**2,127**	2,198	2,399
Refinery capacity utilization			
Crude distillation capacity at 31 December[b]	**2,769**	2,823	2,832
Crude distillation capacity utilization[c]	**72%**	76%	87%
US	**62%**	70%	82%
Europe	**84%**	87%	90%
Rest of World	**84%**	78%	88%

[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).

At the Texas City refinery, the recommissioning work in the aftermath of Hurricane Rita has involved the development of detailed plans to effect the repair, safety-upgrading and safe restart of the process units. The refinery has restarted many process units and the site is producing gasoline, diesel and chemicals products for the US market. By the end of 2007, we had successfully recommissioned the three desulphurization and upgrading units necessary to allow restart of the remaining crude distillation capacity. The final sour crude unit is mechanically complete and is expected to be fully operational during the first quarter of 2008. By mid-2008 we expect most of the economic capability at the Texas City refinery to have been restored.

Despite the partial recommissioning of the Texas City refinery, our US throughputs declined in 2007 due to several operational issues, including the March 2007 fire at the Whiting refinery as well as planned maintenance at our other refineries. By the end of 2007, the Whiting refinery had recommenced sour crude processing and available distillation capacity exceeded 300,000b/d.

The increase in Rest of Europe throughputs in 2007 is primarily related to the purchase of Chevron s 31% interest in the Rotterdam refinery. The decrease in UK throughputs is due to the sale of the Coryton refinery to Petroplus.

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Marketing

Marketing comprises three business areas: Fuels marketing (including ground, aviation and marine fuels, bitumen and LPG), Lubricants (including automotive, marine and industrial lubricants) and Aromatics & 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 PTA, paraxylene (PX) and acetic acid through our Aromatics & Acetyls business.

		thousand barrels per day	
Sales of refined products[a]	**2007**	2006	2005
Marketing sales			
UK[b]	**339**	356	355
Rest of Europe	**1,294**	1,340	1,354
US	**1,533**	1,595	1,634
Rest of World	**640**	581	599
Total marketing sales[c]	**3,806**	3,872	3,942
Trading/supply sales[d]	**1,818**	1,929	1,946
Total refined products	**5,624**	5,801	5,888
			$ million
Proceeds from sale of refined products	**194,979**	177,995	155,098

[a] Excludes sales to other BP businesses and sales of Aromatics & 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	**2007**	2006	2005
Aviation fuel	**490**	488	499
Gasolines	**1,572**	1,603	1,603
Middle distillates	**1,119**	1,170	1,185
Fuel oil	**429**	388	379
Other products	**196**	223	276
Total marketing sales	**3,806**	3,872	3,942

Marketing volumes were 3,806mb/d, slightly lower than last year, reflecting reduced industry demand in Europe and supply disruptions caused by the outage at Whiting refinery.

BP enjoys a strong market share and leading technologies in the Aromatics & 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.

BP supports its businesses through a dedicated Strategic Accounts organization. Strategic Accounts develops strategic relationships with carefully selected large multinational customers 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.

Fuels marketing

Our Fuels marketing strategy focuses on optimising the fuels value chain and delivering refined products to the market. We do this by co-ordinating our marketing, refining and trading activities to maximize synergies across the whole value chain. Our priorities are to operate an advantaged infrastructure and logistics network, drive excellence in operating and transactional processes and deliver compelling customer offers in the various markets where we operate. The fuels business markets a comprehensive range of refined oil products focused on ground fuels, aviation, marine and bitumen sectors.

Ground fuels

The ground fuels business supplies fuel to retail consumers through company-owned and franchised retail sites as well as other channels

including wholesalers and jobbers. It also supplies commercial customers within the road and rail transport sectors.

BP s value creation in ground fuels is obtained through the integration of the value chain from the refinery gates or import hubs across retail and commercial channels to market. Convenience retail offers are managed as an autonomous business model focused on delivering appealing convenience offers across the various markets in which we operate, through the BP Connect, am/pm and Aral brands.

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

			$ million
Store sales[a]	**2007**	2006	2005
UK	**713**	647	628
Rest of Europe	**2,974**	2,821	3,069
US	**1,712**	1,755	1,776
Rest of World	**670**	591	610
Total	**6,069**	5,814	6,083
Direct-managed	**2,609**	2,528	2,489
Franchise	**3,460**	3,286	3,533
Store alliances			61
Total	**6,069**	5,814	6,083

[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.

			Number of retail sites
Retail sites[a]	**2007**	2006	2005
UK	**1,200**	1,300	1,300
Rest of Europe	**7,400**	7,700	7,900
US (excluding jobbers)	**2,500**	2,700	3,100
US jobbers	**9,700**	9,600	9,700
Rest of World	**3,300**	3,300	3,200

Total	**24,100**	24,600	25,200

[a] Retail sites includes all sites operated under a BP brand. Changes in the number of retail sites over time are affected by, among other things, dealer/jobber-owned sites that move to or from the BP brand as their fuel supply agreements expire and are renegotiated in the normal course of business.

At 31 December 2007, BP s worldwide network consisted of some 24,000 locations branded BP, Amoco, ARCO and Aral, around the same as in the previous year.

At 31 December 2007, BP s retail network in the US comprised approximately 12,200 sites, of which approximately 9,700 were owned by jobbers and 500 by franchisees. Our European network amounted to approximately 8,600 sites with a further approximately 3,300 sites in Rest of World. The joint venture between BP and PetroChina (BP-PetroChina Petroleum Company Ltd) started its operation in 2004. The joint venture plans to operate and manage a total network of 500 locations in the Guangdong province and 400 sites were operational as at 31 December 2007. The joint venture with Sinopec commenced operations in 2005. The joint venture plans to build, operate and manage a network of 500 sites in Hangzhou, Ningbo and Shaoxing within Zhejiang province. As at 31 December 2007, 220 of these sites were operational.

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 2007, we sold 462 company-owned sites to dealers, jobbers and franchisees who continue to operate these sites under the BP brand. We also divested an additional 204 company-owned sites to third parties.

Each of our fuels brands, BP, Amoco, ARCO and Aral, carries a very strong offer and we also aim to share best practices between them. Since 2003, we have been upgrading our fuel offer with the introduction of Ultimate gasoline and diesel products. In 2007, we launched Ultimate in Switzerland and Luxembourg and now market Ultimate in 17 countries. In 2007, we launched our Helios Power campaign in the US aimed at reinforcing the BP brand s positioning in key markets.

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Our convenience retail strategy continues to focus on BP s advantaged positions in major cities and growth markets and upgrading our retail offers, while driving operational efficiencies through portfolio optimization including, where appropriate, a transition to franchising. 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 branded store format in each of our key markets. Examples include the BP Connect offer in Europe, the UK partnership with Marks & Spencer Simply Food at selected locations, the am/pm offer in the US and the Aral offer in Germany. At 31 December 2007, our convenience store network consisted of more than 960 BP Connect stores worldwide, and around 1,000 am/pm stores in the US and 1,500 Aral stores in Germany.

In line with BP s intent to simplify the group s operations and improve performance, as well as to position the business for future growth by directly accessing the franchisees entrepreneurial experience and local knowledge, BP has announced that it will sell all of its company-owned and company-operated convenience sites in the US. The majority of sites will be sold to franchisees, with the remaining sites to dealers and large distributors (jobbers). The sale of the sites is expected to be completed by the end of 2009. The sites will continue to market BP-branded fuels in the eastern US and ARCO-branded fuels in the western US. The franchise agreement has a term of 20 years and requires sites to be supplied with BP- or ARCO-branded fuels for the term of the contract.

Aviation fuels

Air BP is one of the world s largest aviation businesses, supplying aviation fuel to the airline, military and general aviation sectors. It supplies customers in approximately 80 countries, has annual marketing sales of 27.4 billion litres (more than 470mb/d) and has relationships with many of the major commercial airlines. Air BP s strategic aim is to strengthen its position in its main existing markets (Europe/US/Middle East), while creating opportunities in emerging economies such as China, where it is the largest foreign investor in the industry.

Marine fuels

The marine fuels business focuses on the distribution and resale of refined fuels to the shipping industry across the world. The business has a strong presence in the marine fuels sector. It has offices in 12 countries and operates in more than 150 ports.

Bitumen

The bitumen business focuses on the distribution and sale of bitumen products for road construction and maintenance. It has a strong presence in the US and in Europe and is exploring opportunities in developing economies, where new infrastructure is being built. It markets bitumen products in seven countries and product sales in 2007 were approximately 45mb/d.

LPG

The LPG business sells bulk, bottled, automotive and wholesale LPG 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 product sales in 2007 were approximately 72mb/d.

Lubricants

We manufacture and market lubricants products and also supply related products and services to business customers and end-consumers in more than 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 the marine and industrial business markets. Customer focus, distinctive brands and superior technology remain the cornerstones of our long-term strategy. BP markets primarily through its major brands, Castrol and BP, as well as Aral in specific markets. The Castrol brand is recognized worldwide and we believe it provides us with a significant competitive advantage. In the automotive lubricants segment, we supply lubricants, other products and related business services to intermediate customers such as retailers and workshops, who in turn serve end-consumers such as 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. BP s marine lubricants business, operating under the BP and Castrol brands, is a market leader with capability to supply in about 1,200 ports. BP also supplies lubricants to the power generation, offshore oil and aviation industries. BP s industrial lubricants business supplies lubricants and value-adding services to the transportation, automotive and metal sectors.

Aromatics & Acetyls

The Aromatics & Acetyls business manufactures and markets 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 & Acetyls strategy is to invest to maintain and grow our advantaged manufacturing positions globally, with an emphasis on growth in Asia, 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 & Acetyls production capacity at 31 December 2007. 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			549	616	1,165	
Rest of Europe						
Belgium						
Geel	1,075	597			1,672	
USA						
Cooper River	1,309				1,309	
Decatur	1,046	1,109		29	2,184	
Texas City		1,302	550[a]	123	1,975	
Rest of World						
China						
Chongqing			211[b]	52	263	(51% of YARACO)[b]