BP PLC
Form 20-F
March 05, 2010

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 20-F

(Mark One)

o **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

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

For the fiscal year ended 31 December 2009

OR

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

OR

o **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)
Dr Byron E Grote
BP p.l.c.
1 St James s Square, London SW1Y 4PD
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Tel +44 (0) 20 7496 4000
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(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

Title of each class	Name of each exchange on which registered
Ordinary Shares of 25c each	**New York Stock Exchange***
4 7/8% Guaranteed Notes due 2010	**New York Stock Exchange**
Floating Rate Guaranteed Extendible Notes	**New York Stock Exchange**
Floating Rate Guaranteed Notes due 2010	**New York Stock Exchange**
5.25% Guaranteed Notes due 2013	**New York Stock Exchange**
Floating Rate Guaranteed Notes due 2011	**New York Stock Exchange**
1.55% Guaranteed Notes due 2011	**New York Stock Exchange**
3.125% Guaranteed Notes due 2012	**New York Stock Exchange**
3.625% Guaranteed Notes due 2014	**New York Stock Exchange**

3.875% Guaranteed Notes due 2015	**New York Stock Exchange**
4.75% Guaranteed Notes due 2019	**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	**18,759,888,123**
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 þ No o

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 o No þ

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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).*

Yes þ No o

*This requirement does not apply to the registrant until its fiscal year ending December 31, 2011.

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 þ Accelerated filer o Non-accelerated filer o

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

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

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 o Item 18 o

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 o No þ

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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, including an unincorporated entity such as a partnership, over which the group has significant influence and that is neither a subsidiary nor a joint venture. Significant influence is the power to participate in the financial and operating policy decisions of an entity but is not control or joint control over those policies.

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.

IFRS
International Financial Reporting Standards.

Joint control
Joint control is the contractually agreed sharing of control over an economic activity, and exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the parties sharing control (the venturers).

Joint venture
A contractual arrangement whereby two or more parties undertake an economic activity that is subject to joint control.

Jointly controlled asset
A joint venture where the venturers jointly control, and often have a direct ownership interest in the assets of the venture. The assets are used to obtain benefits for the venturers. Each venturer may take a share of the output from the assets and each bears an agreed share of the expenses incurred.
Jointly controlled entity
A joint venture that involves the establishment of a corporation, partnership or other entity in which each venturer has an interest. A contractual arrangement between the venturers establishes joint control over the economic activity of the entity.
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
A production-sharing agreement (PSA) is an arrangement through which an oil company bears the risks and costs of exploration, development and production. In return, if exploration is successful, the oil company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of the production remaining after such cost recovery.
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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Business review

Group overview

Our organization

BP is one of the world s leading international oil and gas companies.[a] We operate in more than 80 countries, providing our customers with fuel for transportation, energy for heat and light, retail services and petrochemicals products for everyday items.

As a global group, our interests and activities are 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 two business segments in 2009: Exploration and Production and Refining and Marketing. BP s activities in low-carbon energy are managed through our Alternative Energy business, which is reported within Other businesses and corporate.

Exploration and Production s activities cover three key areas. Upstream activities include oil and natural gas exploration, field development and production. Midstream activities include pipeline, transportation and processing activities related to our upstream activities. Marketing and trading activities include the marketing and trading of natural gas, including liquefied natural gas (LNG), together with power and natural gas liquids (NGLs).

Refining and Marketing s activities include the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum and petrochemicals products and related services.

The two business segments each comprise a number of strategic performance units (SPUs), which are organized along either geographic or activity-related lines. The role of the SPU includes the development of local capability and the fostering of external stakeholder relationships. Each SPU is of a scale that allows for a close focus on performance delivery by its respective segment, which includes the appropriate management of costs.

[a] On the basis of market capitalization, proved reserves and production.

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. The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001. BP s primary share listing is the London Stock Exchange. Ordinary shares are also traded on the Frankfurt Stock Exchange in Germany and, in the US, the company s securities are traded in the form of ADSs. (*See pages 96 to 97 for more details.*)

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.,
501 Westlake Park Boulevard, Houston, Texas 77079.
Tel +1 281 366 2000.

Our group functions and regions support the work of our segments and businesses. Their key objectives are to establish and monitor fit-for-purpose functional standards across the group; to act as centres of deep functional expertise; to access significant leverage with third-party suppliers; and to establish and maintain capabilities among the functional staff employed within our operating businesses. In addition, the head of each region provides the required integration and co-ordination of group activities in a particular geographic area and represents BP to external parties.

Where we operate

BP s worldwide headquarters is in London. The UK is a centre for trading, legal, finance and other business functions as well as three of BP s major global research and technology groups.

We have well-established operations in Europe, the US, Canada, Russia, South America, Australasia, Asia and parts of Africa. Currently, around 67% of the group s capital is invested in Organisation for Economic Co-operation and Development (OECD) countries, with around 40% of our fixed assets located in the US and around 20% in Europe.

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Business review

Our Exploration and Production segment conducts upstream and midstream activities in 30 countries and we are the largest producer of oil and gas in North America. The segment s geographical coverage in these activities currently includes Angola, Azerbaijan, Canada, Egypt, Russia, Trinidad & Tobago (Trinidad), Norway, the UK, the US and locations within Asia Pacific, Latin America, North Africa and the Middle East. Our Exploration and Production segment also includes gas marketing and trading activities, primarily in Canada, Europe and the US. In Russia, we have an important associate through our 50% shareholding in TNK-BP, a major oil company with exploration assets, refineries and other downstream infrastructure.

In Refining and Marketing, we market our products in more than 80 countries, with a particularly strong presence in the US and Europe, as well as major activities in Australia, Southern Africa, India and China. In the US, we own or have a share in five refineries and market primarily under the Amoco, ARCO, BP and Castrol brands. We are one of the largest gasoline retailers in that country. In Europe, we own or have a share in seven refineries and we market extensively across the region, primarily under the Aral, BP and Castrol brands. Our long-established supply and trading activity is responsible for delivering value across the crude and oil products supply chain. Our petrochemicals business maintains a manufacturing position globally, with an emphasis on growth in Asia. We continue to seek opportunities to broaden our activities in growth markets such as China and India.

Our market

Energy markets remained volatile in 2009, reflecting the dramatic drop in world economic activity early in the year and indications of economic recovery in the second half. Looking ahead, the long-term outlook is one of growing demand for energy[a], particularly in Asia, alongside challenges for the industry in meeting this demand. Rising incomes and expanding urban populations are expected to drive demand, while the evolution towards a lower-carbon economy will require technology, innovation and investment.

World oil consumption declined for a second successive year during 2009, with growing demand in non-OECD countries once again more than offset by falling consumption in OECD countries. Average crude oil prices for 2009 were lower than in the previous year, breaking an unprecedented string of seven consecutive annual increases. Natural gas prices also weakened in 2009 and were highly volatile. Refining margins fell sharply as oil demand contracted and substantial amounts of new refining capacity came onstream.

Economic context

The world economy began to show signs of recovery in the latter part of 2009 and this is expected to continue through 2010, but economic growth in 2010 is likely to be muted in the OECD countries. Growth in global oil consumption is expected to resume as the world economy recovers from recession.

In 2009, concerns about the volatility of commodity and financial markets, combined with renewed focus on climate change and the early experiences with efforts to reduce CO_2 emissions in the EU and elsewhere, led to an increased focus on the appropriate role for markets, government oversight and other policy measures relating to the supply and consumption of energy.

The concept of peak oil the time after which less oil is available to the world continues to hold the interest of some commentators, although global proved reserves have tended to rise over time and remain sufficient to support higher levels of production. Meanwhile, the consumer response to higher prices and an increased focus on energy efficiency have served to constrain demand. We expect regulation and taxation of the energy industry and energy users to increase in many areas over the short to medium term.

[a] *World Energy Outlook 2009.* ©OECD/IEA 2009, pages 622-623: Reference Scenario, World .

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Business review

Crude oil prices

Dated Brent for the year averaged $61.67 per barrel, about 37% below 2008 s record average of $97.26 per barrel. Prices began the year at their lowest point as the world economy grappled with the sharpest downturn in modern economic history.

Global oil consumption reflected the economic slowdown, falling by roughly 1.3 million b/d for the year (1.5%)[b], the largest annual decline since 1982. The biggest reductions were early in the year, with OECD countries accounting for the entire global decline. Crude oil prices rose sharply in the second quarter in response to sustained OPEC production cuts and emerging signs of stabilization in the world economy, despite very high commercial oil inventories in the OECD. OPEC members sustained roughly 2.5 million b/d of production cuts[b] implemented in late 2008 and throughout 2009. Additional price increases later in the year were sustained by further positive economic news and signs that the inventory overhang was beginning to correct.

In 2008, the average dated Brent price of $97.26 per barrel was 34% higher than the $72.39 per barrel average seen in 2007. Daily prices began 2008 at $96.02 per barrel, peaked at $144.22 per barrel on 3 July 2008, and fell to $36.55 per barrel at the end of the year. The sharp drop in prices was due to falling demand in the second half of the year, caused by the OECD falling into recession and the lagged effect on demand of high prices in the first half of the year. OPEC had increased production significantly through the first three quarters and, as a result of falling consumption and rising OPEC production, inventories rose. As prices continued to decline, OPEC responded with successive announcements of production cuts in September, October and December.

Looking ahead, in 2010 we expect oil price movements to continue to be driven by the extent of global economic growth and its resulting implications for oil consumption, and by OPEC production decisions.

[a] See footnote d on page 33.

[b] Adapted from *Oil Market Report* (February 2009). ©OECD/IEA 2009.

Natural gas prices

Natural gas prices weakened in 2009 and were volatile. The average US Henry Hub First of Month Index fell to $3.99/mmBtu in 2009, a 56% decrease from the record $9.04/mmBtu average seen in 2008. Recession-induced demand declines and strong production caused prices to drop from $6.16/mmBtu at the start of the year to $2.84/mmBtu in September. However, over the course of the year, the impact was partly offset as US regional gas price differentials narrowed, driven partly by the Rockies Express Pipeline extension allowing the transportation of larger quantities of gas out of the Rockies area. Reduced imports from Canada, slowing US production growth and cooler temperatures allowed prices to recover to $4.49/mmBtu by the end of the year. Prices at the UK National Balancing Point similarly fell to an average of 30.85 pence per therm, 47% below the 2008 average price of 58.12 pence per therm. In 2009, there was a switch of uncontracted LNG cargoes from Asia to Europe, reflecting a shift in relative spot prices. LNG imports to Europe have competed with pipeline imports, where the gas price is often indexed to oil prices, as well as with marginal European gas production. Gas prices were often at or below parity with coal, when translated into the cost of generating power, which led to gas displacing coal in power generation in Europe and the US.

In 2008, average natural gas prices in the US and the UK were higher than in 2007. The Henry Hub First of Month Index, at $9.04/mmBtu, was 32% higher than the 2007 average of $6.86/mmBtu. 2008 s prices peaked at $13.11/mmBtu in July amid robust demand and falling US gas imports, but fell to $6.90/mmBtu in December as demand weakened and production remained strong. In the UK, 2008 average prices of 58.12 pence per therm at the National Balancing Point, were 94% above the 2007 average of 29.95 pence per therm.

Looking ahead, gas markets in 2010 are expected to follow developments in the global economy, but any price movements are likely to be impacted by significant new LNG capacity as it becomes available.

Refining margins

Refining margins fell sharply in 2009 as demand for oil products reduced in the wake of the global economic recession and new refining capacity came onstream, mostly in Asia Pacific. The BP global indicator refining margin

(GIM)[a] averaged $4 per barrel last year, down $2.50 per barrel compared with 2008. Margins in the Far East were particularly badly hit averaging close to zero in Singapore because new refining capacity has been added in the region.

Margins in Europe were about half the 2008 level as the reduction in economic activity meant weaker demand for commercial transport and therefore lower middle distillate consumption. In the US, where refining is more highly upgraded and the transport market more gasoline-orientated, margins were stronger than in Europe.

Refining margins in 2008 were lower than in 2007, with the BP GIM decreasing to an average of $6.50 per barrel from $9.94 per barrel in 2007. The premium for light products above fuel oils remained high, reflecting a continuing shortage of upgrading capacity and the favouring of fully upgraded refineries over less complex sites.

Looking ahead, refining margins are likely to remain under pressure through 2010, with capacity already exceeding demand and additional new capacity expected to come onstream during the year.

Business review

Long-term outlook

Recent economic conditions have weakened global demand for primary energy, but a number of forecasts predict a return to growth in the medium term. This is underpinned by continuing population growth and by generally rising living standards in the developing world, including the expansion of urban populations.

Under the International Energy Agency s (IEA) reference scenario, global energy demand is projected to increase by around 40% between 2007 and 2030[a]. That scenario also projects that fossil fuels will still be satisfying as much as 80% of the world s energy needs in 2030. At current rates of consumption, the world has enough proved reserves of fossil fuels to meet these requirements[b] if investment is permitted to turn those reserves into production capacity. However, to meet the potential growth in demand, continued investment in new technology will be required in order to boost recovery from declining fields and commercialize currently inaccessible resources. For example, in oil alone, where we believe there are reserves in place to satisfy approximately 40 years demand at current rates of consumption[b], we estimate that our industry will need to bring nearly 50 million barrels per day of new capacity onstream by 2030 if it is to meet the increased demand. To play their part in achieving this, energy companies such as BP will need secure and reliable access to as-yet undeveloped resources. We estimate that more than 80% of the world s oil resources are held by Russia, Mexico and members of OPEC areas where international oil companies are frequently limited or prohibited from applying their technology and expertise to produce additional supply. New partnerships will be required to transform latent resources into much-needed proved reserves.

A more diverse mix of energy will also be required to meet this increased demand. Such a mix is likely to include both unconventional fossil fuel resources such as oil sands, coalbed methane and natural gas produced from shale formations and renewable energy sources such as wind, biofuels and solar power. Beyond simply meeting growth in overall demand, a diverse mix would also help to provide enhanced national and global energy security while supporting the transition to a lower-carbon economy. Improving the efficiency of energy use will also play a key role in maintaining energy market balance in the future.

Along with increasing supply, we believe the energy industry will be required to make hydrocarbons cleaner and more efficient to use particularly in the critical area of power generation, for which the key hydrocarbons are currently coal and gas. The world has reserves of coal for around 120 years at current consumption rates[b], but coal produces more carbon than any other fossil fuel. Carbon capture and storage (CCS) may help to provide a path to cleaner coal, and BP is investing in this area, but CCS technologies still face significant technical and economic issues and are unlikely to be in operation at scale for at least a decade.

In contrast, we believe that in many countries natural gas has the potential to provide the most significant reductions in carbon emissions from power generation in the shortest time and at the lowest cost. These reductions can be achieved using technology available today. Combined- cycle turbines, fuelled by natural gas, produce around half the CO_2 emissions of coal-fired power, and are cheaper and quicker to build. It is estimated that there are reserves of natural gas in place equivalent to 60 years consumption at current rates[b] and they are rising as new skills and technology unlock new unconventional gas resources. For these reasons, gas is looking to be an increasingly attractive resource in meeting the growing demand for energy, playing a greater role as a key part of the energy future.

At the same time, alternative energies also have the potential to make a substantial contribution to the transition to a lower-carbon economy, but this will require investment, innovation and time. Currently, wind, solar, wave, tide and geothermal energy account for only around 1% of total global consumption[c]. Even in the most aggressive scenario put forward by the IEA, these forms of energy are estimated to meet no more than 5% of total demand in 2030[d].

If industry and the market are to meet the world s growing demand for energy in a sustainable way, governments will be required to set a stable and enduring framework. As part of this, governments will need to provide secure access for exploration and development of fossil fuel resources, define mutual benefits for resource owners and development partners, and establish and maintain an appropriate legal and regulatory environment, including a mechanism for recognizing and incorporating the cost of reducing carbon emissions.

[a] *World Energy Outlook 2009.* ©OECD/IEA 2009, pages 622-623: Reference Scenario, World . The IEA s reference scenario describes what would happen if, among other things, governments were to take no new initiatives bearing

on the energy sector, beyond those already adopted by mid-2009.

[b] *BP Statistical Review of World Energy June 2009*. This estimate is not based on proved reserves as defined by SEC rules.

[c] Adapted from *World Energy Outlook 2009.* ©OECD/IEA 2009, page 74. The IEA s 450 policy scenario assumes governments adopt commitments to limit the long-term concentration of greenhouse gases in the atmosphere to 450 parts per million of CO_2 equivalent.

[d] *World Energy Outlook 2009.* ©OECD/IEA 2009, page 212: World primary energy demand by fuel in the 450 Scenario (Mtoe) .

Business review

Our strategy

The priorities that drove our success in 2009 safety, people and performance remain the foundation of our agenda as we build on our momentum and work to further enhance our competitive position.

Our strategy is to invest competitively to grow oil and gas production while working to drive performance across the group through enhanced operating efficiency, capital efficiency and cost efficiency.

To meet growing world demand, BP is committed to exploring, developing and producing more fossil fuel resources; manufacturing, processing and delivering better and more advanced products; and enabling the transition to a lower-carbon future. We aim to do this while operating safely, reliably and in compliance with the law. We strive to run our business within the discipline of a clear financial framework.

In 2009, we improved our overall competitive performance by enhancing operating performance and reducing complexity and costs. We believe we can continue to compete successfully through our ability to access resources and deliver high-quality products and service to our customers. We intend to remain focused on the application of technology and developing relationships based on a commitment to long-term partnerships and mutual advantage. Our intention is to generate and sustain business momentum and growth through a rigorous process of continuous improvement and an ongoing focus on safety, people and performance.

Safety, reliability, compliance and continuous improvement

Safe, reliable and compliant operations remain the group s first priority. A key enabler for this is the BP operating management system (OMS), which provides a common framework for all BP operations, designed to achieve consistency and continuous improvement in safety and efficiency. OMS includes mandatory practices, such as integrity management and incident investigation, which are designed to address particular risks. In addition, it enables each site to focus on the most important risks in its own operations and sets out procedures on how to manage them in accordance with the group-wide framework. Further information on our safety priorities and performance can be found on page 42.

The right people, skills and capability

It is vital that we develop and deploy people with the skills, capability and behaviours required to meet our objectives. Despite a tight global recruitment market for some of our core technical disciplines, we have been successful in building capacity and getting the right people with the right skills in the right place. We are now going further, strengthening the culture within BP through a commitment to continuous improvement in operations and enhancing the capabilities, technical expertise and organizational quality needed to drive performance.

Our people strategy has already resulted in refreshed group leadership and senior management teams, recruitment focused on individuals with strong operational and technical expertise, and appropriate reward for performance at all levels.

Enhanced performance and efficiency

Our strategy aims to create value for shareholders by investing to deliver growth in our Exploration and Production business together with enhanced efficiency and high-quality earnings and returns throughout our operations.

In Exploration and Production, our strategy is to invest to grow production safely, reliably and efficiently. We intend to achieve this by strengthening our portfolio of leadership positions in the world s most prolific hydrocarbon basins, enabled by the development and application of technology and the building of strong relationships based on mutual advantage. We also intend to sustainably drive cost and capital efficiency in accessing, finding, developing and producing resources, enabled by deep technical capability and a culture of continuous improvement.

In Refining and Marketing, our strategic focus is on enhancing portfolio quality, integrating activities across value chains and performance efficiency. We expect to continue building our business around advantaged assets in material and significant energy markets while improving the safety and reliability of our operations. Our objective is to achieve sector-leading levels of performance on a sustainable basis. To achieve this, we need to continue upgrading the manufacturing capabilities within our integrated fuels value chains to achieve the best capacity utilization and margin capture. We continue to explore appropriate opportunities to deploy downstream capital into faster-growing non-OECD markets. We also intend to continue our selective investment in our international businesses, which include petrochemicals and lubricants, where we see potential to deliver strong and sustainable returns.

In Alternative Energy, we have focused our investments in the areas where we believe we can create the greatest competitive advantage. We have substantial businesses in wind and solar power and are developing advanced biofuels and low-carbon energy technologies such as hydrogen power and carbon capture and storage.

Our determination to drive efficiency through our businesses has proved vital to our performance during a period of recession and we believe that it will remain critical to our future prospects as the global economy recovers and evolves.

Looking further ahead

As discussed in the Our market section of this Annual Report on Form 20-F (*see pages 7 to 9*), we expect that the world will require a more diverse energy mix as the basis for a secure supply of energy over time. We intend to play a central role in meeting the world s continued need for hydrocarbons, with our Exploration and Production and Refining and Marketing activities remaining at the core of our strategy. We are also creating long-term options for the future in new energy technology and low-carbon energy businesses. Current investment is focused on wind, solar and biofuels as potential sources of resource diversification for the world, and we are investing in carbon capture and storage as an enabling technology. We believe that this focused portfolio has the potential to be a material source of value creation for BP in the longer term (*see pages 38 to 39*). We are also enhancing our capabilities in natural gas, which is likely to play a greater role as a key part of the energy future. We intend to lead and shape this transition, including through the application of advanced technology to unlock sources of unconventional gas, while working to achieve sector-leading levels of return for our shareholders.

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Business review

Our performance

2009 has been a successful year for BP, with positive financial and operational momentum despite an extremely turbulent global financial environment.

Safety

Good progress has been made on underpinning improved safety performance in 2009. Throughout the year, we continued to focus on training and enhancing procedures across the organization. Significantly, 2009 was an important year in the development of OMS. By the end of 2009, around 80% of our operating sites were using the system, including all our operated refineries and petrochemicals plants. (*See Safety on page 42 for more information on OMS.*)

In 2009, a third-party-operated helicopter carrying contractors from BP s Miller platform crashed in the North Sea, resulting in the tragic loss of 16 lives. In addition, BP sustained two fatalities within our own operations. We deeply regret the loss of these lives.

Recordable injury frequency (RIF, a measure of the number of reported injuries per 200,000 hours worked) was 0.34, significantly below 2008 and 2007 levels of 0.43 and 0.48, respectively. Reported oil spills greater than one barrel were 234 in 2009 compared with 335 in 2008 and 340 in 2007. Our environmental measure that tracks greenhouse gas (GHG) emissions[a] increased in 2009 to 65.0 million tonnes of carbon dioxide equivalent, compared with 61.4 million tonnes in 2008. The primary reason for this increase is the growth of our business, including the significant increase in our US refining throughputs, the start-up of our Tangguh LNG project in Indonesia and the continued success of our Gulf of Mexico deepwater operations, including Thunder Horse.

People

During 2009 we made further significant progress in generating a stronger performance focus and in fostering a culture that attributes more value to deep specialist skills and expertise. At the same time, we continued to improve operational efficiency and reduce overheads.

Non-retail headcount was reduced by 4,400 (6%) in 2009. Overall, the number of employees (including retail staff) was reduced by 11,700 in 2009.

Performance

Against the backdrop of the global recession, we delivered a strong performance in 2009. Profit and cash flow were lower than in 2008, due primarily to a much weaker price environment, although the impact was partially offset by better operational performance and lower costs across the group as we implemented our efficiency programmes. Notable achievements include:

Exploration and Production

- Replacing 129% of our proved reserves, on a combined basis of subsidiaries and equity-accounted entities.
- Delivering a 5% underlying growth in production[b].
- Reducing unit production costs by 12%.
- Achieving a strong gas marketing and trading performance.
- Accessing new resources in Egypt, the Gulf of Mexico, Indonesia, Iraq and Jordan.
- Making the Tiber discovery in the Gulf of Mexico at a depth of over 35,000 feet, the deepest oil and gas discovery well ever drilled.
- Making three further discoveries in Block 31, Angola.
- Starting up Tangguh in Indonesia and six other major projects in the Gulf of Mexico, Trinidad and Russia.

Refining and Marketing

- Restoring our overall performance so that it is once again competitive with our supermajor peers.

Achieving a Solomon refining availability[c] of 93.6%, which is an increase of almost five percentage points compared with 2008.

Reducing costs across the segment by more than 15%[d].

Delivering a strong supply and trading performance.

Performing strongly in our international businesses, despite the weak environment.

Delivering simplification and lower costs through integration in the fuels value chains.

Simplifying the segment s footprint in aviation and lubricants and completing the transfer of our US convenience retail business to a franchise operation.

Successfully exiting from our ground fuels marketing business in Greece.

[a] See footnote a in Environment on page 43.

[b] Underlying production growth excludes the effect of entitlement changes in our production-sharing agreements (driven by changes in oil and gas prices) and the effect of OPEC quota restrictions.

[c] Refining availability represents Solomon Associates operational availability, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory maintenance downtime.

[d] Based on Refining and Marketing s share of production and manufacturing expenses plus distribution and administration expenses.

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Selected financial and operating information

This information, insofar as it relates to 2009, has been extracted or derived from the audited consolidated financial statements of the BP group presented on pages 107 to 182. 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.

$ million except per share amounts

	2009	2008	2007	2006	2005
Income statement data					
Sales and other operating revenues from continuing operations[a]	**239,272**	361,143	284,365	265,906	239,792
Profit before interest and taxation from continuing operations[a]	**26,426**	35,239	32,352	35,658	32,182
Profit from continuing operations[a]	**16,759**	21,666	21,169	22,626	22,133
Profit for the year	**16,759**	21,666	21,169	22,601	22,317
Profit for the year attributable to BP shareholders	**16,578**	21,157	20,845	22,315	22,026
Capital expenditure and acquisitions[b]	**20,309**	30,700	20,641	17,231	14,149
Per ordinary share cents					
Profit for the year attributable to BP shareholders					
Basic	**88.49**	112.59	108.76	111.41	104.25
Diluted	**87.54**	111.56	107.84	110.56	103.05
Profit from continuing operations attributable to BP shareholders[a]					
Basic	**88.49**	112.59	108.76	111.54	103.38
Diluted	**87.54**	111.56	107.84	110.68	102.19
Dividends paid per share cents	**56.00**	55.05	42.30	38.40	34.85
pence	**36.417**	29.387	20.995	21.104	19.152
Ordinary share data[c]					
Average number outstanding of 25 cent ordinary shares (shares million undiluted)	**18,732**	18,790	19,163	20,028	21,126
Average number outstanding of 25 cent ordinary shares (shares million diluted)	**18,936**	18,963	19,327	20,195	21,411
Balance sheet data					

Total assets	**235,968**	228,238	236,076	217,601	206,914
Net assets	**102,113**	92,109	94,652	85,465	80,450
Share capital	**5,179**	5,176	5,237	5,385	5,185
BP shareholders equity	**101,613**	91,303	93,690	84,624	79,661
Finance debt due after more than one year	**25,518**	17,464	15,651	11,086	10,230
Net debt to net debt plus equity[d]	**20%**	21%	22%	20%	17%

[a] Excludes Innovene, which was treated as a discontinued operation in accordance with IFRS 5 Non-current Assets Held for Sale and Discontinued Operations in 2005 and 2006.

[b] 2008 included capital expenditure of $2,822 million and an asset exchange of $1,909 million, both in respect of our transaction with Husky, as well as capital expenditure of $3,667 million in respect of our transactions with Chesapeake (*see page 49*). 2007 included $1,132 million for the acquisition of Chevron s Netherlands manufacturing company. Capital expenditure in 2006 included $1 billion in respect of our investment in Rosneft. 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.

[d] Net debt and the ratio of net debt to net debt plus equity ratio are non-GAAP measures. We believe that these measures provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total. The net debt ratio enables investors to see how significant net debt is relative to equity from shareholders.

Profits

Profit attributable to BP shareholders for the year ended 31 December 2009 was $16,578 million, including inventory holding gains, net of tax, of $2,623 million and a net charge for non-operating items, after tax, of $1,067 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $445 million relative to management s measure of performance. Inventory holding gains and losses, net of tax, are described in footnote (a) on page 49. More information on non-operating items and fair value accounting effects can be found on pages 54-55.

Profit attributable to BP shareholders for the year ended 31 December 2008 was $21,157 million, including inventory holding losses, net of tax, of $4,436 million and a net charge for non-operating items, after tax, of $796 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $146 million relative to management s measure of performance.

Profit attributable to BP shareholders for the year ended 31 December 2007 was $20,845 million, including inventory holding gains, net of tax, of $2,475 million and a net charge for non-operating items, after tax, of $373 million. In addition, fair value accounting effects had an unfavourable impact, net of tax, of $198 million relative to management s measure of performance.

The primary additional factors affecting profit for 2009, compared with 2008, were lower realizations and refining margins, partly offset by higher production, stronger operational performance and lower costs.

The primary additional factors reflected in profit for 2008, compared with 2007, were higher realizations, a higher contribution from the gas marketing and trading business, improved oil supply and trading performance, improved marketing performance and strong cost management; however, these positive effects were partly offset by weaker refining margins, particularly in the US, higher production taxes, higher depreciation, and adverse foreign exchange impacts.

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Business review

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]

	2009[f]	2008	2007	2006	2005
Crude oil production for subsidiaries (thousand barrels per day)	**1,400**	1,263	1,304	1,351	1,423
Crude oil production for equity-accounted entities (thousand barrels per day)	**1,135**	1,138	1,110	1,124	1,139
Natural gas production for subsidiaries (million cubic feet per day)	**7,450**	7,277	7,222	7,412	7,512
Natural gas production for equity-accounted entities (million cubic feet per day)	**1,035**	1,057	921	1,005	912
Estimated net proved crude oil reserves for subsidiaries (million barrels)[b]	**5,658**	5,665	5,492	5,893	6,360
Estimated net proved crude oil reserves for equity-accounted entities (million barrels)[c]	**4,853**	4,688	4,581	3,888	3,205
Estimated net proved natural gas reserves for subsidiaries (billion cubic feet)[d]	**40,388**	40,005	41,130	42,168	44,448
Estimated net proved natural gas reserves for equity-accounted entities (billion cubic feet)[e]	**4,742**	5,203	3,770	3,763	3,856

[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 and ability to make lifting and sales arrangements independently, and include minority interests in consolidated operations.

[b] Includes 23 million barrels (21 million barrels at 31 December 2008 and 20 million barrels at 31 December 2007) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[c] Includes 243 million barrels (216 million barrels at 31 December 2008 and 210 million barrels at 31 December 2007) in respect of the 6.86% minority interest in TNK-BP (6.80% at 31 December 2008 and 6.51% at 31 December 2007).

[d] Includes 3,068 billion cubic feet of natural gas (3,108 billion cubic feet at 31 December 2008 and 3,211 billion cubic feet at 31 December 2007) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[e] Includes 131 billion cubic feet (131 billion cubic feet at 31 December 2008 and 68 billion cubic feet at 31 December 2007) in respect of the 5.79% minority interest in TNK-BP (5.92% at 31 December 2008 and 5.88% at 31 December 2007).

[f] On 31 December 2008, the SEC published a revision of Rule 4-10 (a) of Regulation S-X for the estimation of reserves. These revised rules form the basis of the 2009 year-end estimation of proved reserves and the application of the technical aspects resulted in an immaterial increase of less than one per cent to BP s total proved reserves.

[a] Combined basis of subsidiaries and equity-accounted entities, on a basis consistent with general industry practice.

[b] On 31 December 2008 the SEC published a revision of Rule 4-10 (a) of Regulation S-X for the estimation of reserves. These revised rules form the basis of the 2009 year-end estimation of proved reserves and the application of the technical aspects resulted in an immaterial increase of less than 1% to BP s total proved reserves.

[c] Crude oil, condensate and natural gas liquids.

During 2009, 1,908 million barrels of oil and natural gas, on an oil equivalent[a] basis (mmboe), were added, excluding purchases and sales, to BP s proved reserves (1,113mmboe for subsidiaries and 795mmboe for equity-accounted entities). At 31 December 2009, BP s proved reserves were 18,292mmboe (12,621mmboe for subsidiaries and 5,671mmboe for equity-accounted entities). Our proved reserves in subsidiaries are located in the US (45%), South America (15%), Australasia (10%), Africa (10%) and the UK (9%). Our proved reserves in equity-accounted entities are located in Russia (69%), South America (21%), and Rest of Asia (9%).

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

Our total hydrocarbon production during 2009 averaged 3,998mboe/d (2,684mboe/d for subsidiaries and 1,314mboe/d for equity-accounted entities). This represents an increase of 4% (an increase of 6% for liquids and an increase of 2% for gas) when compared with 2008. In aggregate, after adjusting for entitlement impacts in our production-sharing agreements (PSAs) and the effect of OPEC quota restrictions, production was 5% higher than 2008. Our total hydrocarbon production during 2008 averaged 3,838mboe/d (2,517mboe/d for subsidiaries and 1,321mboe/d for equity accounted-entities). This represented an increase of 0.5% (a decrease of 0.5% for liquids and an increase of 2% for gas) when compared with 2007. In aggregate, after adjusting for entitlement impacts in our PSAs, 2008 production was 5% higher than 2007.

Acquisitions and disposals

There were no significant acquisitions in 2009. Disposal proceeds in 2009 were $2,681 million, principally from the sale of our interests in BP West Java Limited, Kazakhstan Pipeline Ventures LLC and LukArco, and the sale of our ground fuels marketing business in Greece and retail churn in the US, Europe and Australasia. Further proceeds from the sale of LukArco are receivable in the next two years. See Financial statements Note 3 on page 122.

In 2008, we completed an asset exchange with Husky Energy Inc., and asset purchases from Chesapeake Energy Corporation as described on page 49.

In 2007, BP acquired Chevron s Netherlands manufacturing company, Texaco Raffiniderij Pernis B.V. The acquisition included Chevron s 31% minority shareholding in Nerefco and certain associated assets. 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.

Business review

Risk factors

We urge you to consider carefully the risks described below. If any of these risks occur, we might fail to deliver on our strategic priorities, which are expressed in terms of safety, people and performance (*see page 10*). Our business, financial condition and results of operations could suffer and the trading price and liquidity of our securities could decline.

In the current uncertain financial and economic environment, certain risks may gain more prominence either individually or when taken together. Oil and gas prices are likely to remain volatile with average prices and margins influenced by changes in supply and demand. This is likely to exacerbate competition in all businesses, which may impact costs and margins. At the same time, governments are facing greater pressure on public finances, which may increase their motivation to intervene in the fiscal and regulatory frameworks for the oil and gas industry, including the risk of increased taxation. The financial and economic situation may have a negative impact on third parties with whom we do, or may do, business. Any of these factors may affect our results of operations, financial condition and liquidity.

Capital markets have regained some confidence after the recent crisis but if there are extended periods of constraints in these markets, at a time when cash flows from our business operations may be under pressure, our ability to maintain our long-term investment programme may be impacted with a consequent effect on our growth rate, and may impact shareholder returns, including dividends and share buybacks, or share price. Decreases in the funded levels of our pension plans may also increase our pension funding requirements.

Our system of risk management identifies and provides the response to 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 an inability to capture opportunities, threats materializing, inefficiency and non-compliance with laws and regulations.

The risks are categorized against the following areas: strategic; compliance and control; and operational.

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 grow or even maintain our production.

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 fall in oil and natural gas prices, a prolonged period of low prices or other indicators would lead to further reviews for impairment of the group s oil and natural gas properties. Such reviews would reflect management s view of long-term oil and natural gas prices and 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. Rapid material and/or sustained change in oil, gas and product prices can impact the validity of the assumptions on which strategic decisions are based and, as a result, the ensuing actions derived from those decisions may no longer be appropriate. A prolonged period of low oil prices may impact our ability to maintain our long-term investment programme with a consequent effect on our growth rate and may impact shareholder returns, including dividends and share buybacks, or share price. Periods of global recession could impact the demand for our products, the prices at which they can be sold and affect the viability of the markets in which we operate.

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 a 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, taxes, reduced profitability from changes in operating costs, and revenue generation and strategic growth opportunities being impacted. Our commitment to the transition to a lower-carbon economy may create expectations for our activities, and the level of participation in alternative energies carries reputational, economic and technology risks.

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. In particular, our investments in Russia could be adversely affected by heightened political and economic environment risks.

We set ourselves high standards of corporate citizenship and aspire to contribute to a better quality of life through the products and services we provide. 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, petrochemicals 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.

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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.
Reserves replacement
Successful execution of our group strategy depends critically on sustaining long-term reserves replacement. If upstream resources are not progressed in a timely and efficient manner, we will be unable to sustain long-term replacement of reserves.
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. A credit crisis affecting banks and other sectors of the economy could impact the ability of counterparties to meet their financial obligations to the group. It could also affect our ability to raise capital to fund growth.

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 and revenues.

For more information on financial instruments and financial risk factors see Financial statements Note 24 on page 142.

Compliance and control 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 and health and safety 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. Failure to respond to changes in trading regulations could result in regulatory action and damage to our reputation. 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.

For more information on environmental regulation, see Environment on pages 43-45.

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 ethical misconduct or non-compliance with applicable laws and regulations could be damaging to our reputation and shareholder value. Multiple events of non-compliance could call into question the integrity of our operations.

For certain legal proceedings involving the group, *s*ee Legal proceedings on pages 95-96.

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.
Reporting
External reporting of financial and non-financial data is reliant on the integrity of systems and people. Failure to report data accurately and in compliance with external standards could result in regulatory action, legal liability and damage

to our reputation.
Operational risks
Process safety
Inherent in our operations are hazards that require continuous 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, or loss of production and could result in regulatory action, legal liability and damage to our reputation.
Personal safety
Inability to provide safe environments for our workforce and the public could lead to injuries or loss of life and could result in regulatory action, legal liability and damage to our reputation.
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. Failure to comply with environmental laws, regulations and permits could lead to damage to the environment and could result in regulatory action, legal liability and damage to our reputation.
Security
Security threats require continuous oversight and control. Acts of terrorism against our plants and offices, pipelines, transportation or computer systems could severely disrupt business and operations and could cause harm to people.
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 involve 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.

Business review

Major project delivery
Successful execution of our group plan depends critically on implementing the activities to deliver the major projects over the plan period. Poor delivery of any major project that underpins production growth and/or a major programme designed to enhance shareholder value could adversely affect our financial performance.
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.
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.
People and capability
Successful recruitment of new staff, employee training, development and long-term renewal of skills, in particular technical capabilities such as petroleum engineers and scientists, are key to implementing our plans. Inability to develop the human capacity and capability across the organization could jeopardize performance delivery.
Treasury and trading activities
In the normal course of business, we are subject to operational risk around our treasury and trading activities. Control of these activities is highly dependent on our ability to process, manage and monitor a large number of complex transactions across many markets and currencies. Shortcomings or failures in our systems, risk management methodology, internal control processes or people could lead to disruption of our business, financial loss, regulatory intervention or damage to our reputation.
Our systems of control
The board is responsible for the direction and oversight of BP. The board has set an overall goal for BP, which is to maximize long-term shareholder value through the allocation of its resources to activities in the oil, natural gas, petrochemicals and energy businesses. The board delegates authority for achieving this goal to the group chief executive (GCE).

The board maintains five permanent committees that are composed entirely of non-executives. The board and its committees monitor, among other things, the identification and management of the group s risks both financial and non-financial. During the year, the board s committees engaged with executive management, the general auditor and other monitoring and assurance providers (such as the group compliance and ethics officer and the external auditor) on a regular basis as part of their oversight of the group s risks. Significant incidents that occurred and management s response to them were considered by the appropriate committee and reported to the board. (*See Board performance report on pages 65 to 76.*)

The GCE maintains a comprehensive system of internal control. This comprises the holistic set of management systems, organizational structures, processes, standards and behaviours that are employed to conduct our business and deliver returns for shareholders. The system is designed to meet the expectations of internal control of the Combined Code in the UK and of COSO (committee of the sponsoring organizations for the Treadway Commission) in the US. It addresses risks and how we should respond to them as well as the overall control environment. Each component of the system has been designed to respond to a particular type or collection of risks. Material risks are described within the Risk factors section (*see pages 14 to 16*).

Key elements of our system of internal control are: the control environment; the management of risk and operational performance (including in relation to financial reporting); and the management of people and individual performance. Controls include the BP code of conduct, our leadership framework and our principles for delegation of authority, which are designed to make sure employees understand what is expected of them.

As part of the control system, the GCE s senior team known as the executive team is supported by sub-committees that are responsible for and monitor specific group risks. These include the group operations risk committee (GORC), the group financial risk committee (GFRC), the group people committee (GPC), and the group disclosures committee (GDC), which reviews the disclosures, controls and procedures over reporting.

Operations and investments are conducted and reported in accordance with, and associated risks are thereby managed through, relevant standards and processes. These range from group standards, which set out processes for major areas such as safety and integrity, through to detailed administrative instructions on issues such as fraud reporting. The GCE conducts regular performance reviews with the segments and key functions to monitor performance and the management of risk and to intervene if necessary. People management is based on performance objectives, through which individuals are accountable for delivering specific elements of the group plan within agreed boundaries.

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Business review

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 , aims , should , may , objective , is likely to , intends , believes , plan expressions. In particular, among other statements, (i) certain statements in Business review (pages 6-59), including under the headings Outlook , with regard to strategy, management aims and objectives, future capital expenditure, the future scrip dividend programme, future hydrocarbon production volume and the group s ability to satisfy its long-term sales commitments from future supplies available to the group, 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 Business review (pages 6-48) with regard to anticipated energy demand and consumption, global economic recovery, oil and gas prices, global reserves, expected future energy mix and the potential for cleaner and more efficient sources of energy, management aims and objectives, strategy, production, petrochemical and refining margins, anticipated investment in Alternative Energy, anticipated future project developments, growth of the international businesses, Refining and Marketing investments, reserves increases through technological developments, with regard to planned investment or other projects, timing and ability to complete announced transactions and future regulatory actions; and (iii) the statements in Business review (pages 49-59) with regard to the plans of the group, the cost of and provision for future remediation programmes and environmental operating and capital expenditures, taxation, liquidity and costs for providing pension and other post-retirement benefits; and including under Liquidity and capital resources Trend Information, with regard to global economic recovery, oil and gas prices, petrochemical and refining margins, production, demand for petrochemicals, production and production growth, depreciation, underlying average quarterly charge from Other businesses and corporate, costs, foreign exchange and energy costs, capital expenditure, timing and proceeds of divestments, balance of cash inflows and outflows, dividend and optional scrip dividend, cash flows, shareholder distributions, gearing, working capital, guarantees, expected payments under contractual and commercial commitments and purchase obligations; 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; actions by regulators; 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 14-16. 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.

Further note on certain activities

During the period covered by this report, non-US subsidiaries or other non-US entities of BP, conducted limited activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of Terrorism (Sanctioned Countries). These activities continue to be insignificant to the group s financial condition and results of operations.

BP has interests in, and is the operator of, two fields and a pipeline located outside Iran in which the National Iranian Oil Company (NIOC) and an affiliated entity have interests. BP buys crude oil, refinery and petrochemicals feedstocks, blending components and LPG of Iranian origin or from Iranian counterparties primarily for sale to third parties in Europe and a small portion is used by BP in its own facilities in South Africa and Europe. Until recently BP held an equity interest in an Iranian joint venture that has a blending facility and markets lubricants for sale to domestic consumers. In January 2010, BP restructured its interest in the joint venture and currently maintains its involvement through certain contractual arrangements, which it keeps under review in light of pending legislative developments in the US. 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 petrochemicals plants in Iran.

BP sells lubricants in Cuba through a 50:50 joint venture there and in 2009 purchased a cargo of naphtha from a non-Cuban counterparty that was loaded in Cuba. In Syria, lubricants are sold through a distributor and BP obtains crude oil and refinery feedstocks for sale to third parties in Europe. In addition, BP sells crude oil and refined products into Syria.

BP supplies fuels and lubricants to airlines and shipping companies from Sanctioned Countries at airports and ports located outside these countries.

BP monitors its activities with Sanctioned Countries and keeps them under review to ensure compliance with applicable laws and regulations of the US and other countries where BP operates.

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Exploration and Production

Our Exploration and Production segment includes upstream and midstream activities in 30 countries, including Angola, Azerbaijan, Canada, Egypt, Russia, Trinidad & Tobago (Trinidad), Norway, the UK, the US and locations within Asia Pacific, Latin America, North Africa and the Middle East, as well as gas marketing and trading activities, primarily in Canada, Europe and the US. Upstream activities involve oil and natural gas exploration and field development and production. Our exploration programme is currently focused around Angola, Egypt, the deepwater Gulf of Mexico, Libya, the North Sea, Oman and onshore US. Major development areas include Algeria, Angola, Asia Pacific, Azerbaijan, Egypt and the deepwater Gulf of Mexico. During 2009, production came from 21 countries. The principal areas of production are Angola, Asia Pacific, Azerbaijan, Egypt, Latin America, the Middle East, Russia, Trinidad, the UK and the US.

Midstream activities involve the ownership and management of crude oil and natural gas pipelines, processing facilities and export terminals, LNG processing facilities and transportation, and our NGL extraction businesses in the US, the UK, Canada and Indonesia. Our most significant midstream pipeline interests are the Trans-Alaska Pipeline System in the US, the Forties Pipeline System and the Central Area Transmission System pipeline, both in the UK sector of the North Sea, the South Caucasus Pipeline (SCP), which takes gas from Azerbaijan through Georgia to the Turkish border and the Baku-Tbilisi-Ceyhan pipeline, running through Azerbaijan, Georgia and Turkey. Major LNG activities are located in Trinidad, Indonesia and Australia. BP is also investing in the LNG business in Angola.

Additionally, our activities include the marketing and trading of natural gas, power and natural gas liquids. These activities provide routes into liquid markets for BP s gas and power, and generate margins and fees associated with the provision of physical and financial products to third parties and additional income from asset optimization and trading.

Our oil and natural gas production assets are located onshore and 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.

Upstream operations in Argentina, Bolivia, Chile, Abu Dhabi, Kazakhstan, Venezuela and Russia, as well as some of our operations in Angola, Canada and Indonesia, are conducted through equity-accounted entities.

Our market

The market environment in which we operate was particularly challenging during 2009, with crude oil and natural gas prices at lower levels than we have experienced in recent history.

The annual average crude oil price declined in 2009 for the first time since 2001, breaking an unprecedented string of seven consecutive annual increases. Dated Brent for the year averaged $61.67 per barrel, about 37% below 2008 s record average of $97.26 per barrel. Prices were lowest at the beginning of the year as the world economy grappled with the sharpest downturn in modern economic history.

In 2010, we expect oil market movements to continue to be driven by developments in the world economy, by their resulting implications for oil consumption, and by OPEC production decisions.

Natural gas prices weakened in 2009 and were volatile. The average US Henry Hub First of Month Index fell to $3.99/mmBtu in 2009, a 56% decrease from the record $9.04/mmBtu average seen in 2008.
Recession-induced demand declines and strong production caused prices to drop from $6.16/mmBtu at the start of the year to $2.84/mmBtu in September. However, over the course of the year, the impact was partly offset as US regional gas price differentials narrowed, driven partly by the Rockies Express Pipeline extension allowing the transportation of larger quantities of gas out of the Rockies area. Reduced imports from Canada, slowing US production growth and cooler temperatures allowed prices to recover to $4.49/mmBtu by the end of the year. Prices at the UK National Balancing Point similarly fell to an average of 30.85 pence per therm, 47% below the 2008 average price of 58.12 pence per therm.

In 2009, there was a switch of uncontracted LNG cargoes from Asia to Europe, reflecting a shift in relative spot prices. LNG imports to Europe have competed with pipeline imports, where the gas price is often indexed to oil prices, as well as with marginal European gas production. On an energy equivalent basis, gas prices were often at or below parity with coal, which led to gas displacing coal in power generation in Europe and the US.

In the event of any recovery in the economy in 2010, both the US and UK gas markets are expected to benefit although the price upside is likely to be constrained as a result of a record amount of LNG expected to become available globally.

Our strategy

Our strategy is to invest to grow production safely, reliably and efficiently by:

Strengthening our portfolio of leadership positions in the world s most prolific hydrocarbon basins, enabled by the development and application of technology and strong relationships based on mutual advantage.

Sustainably driving cost and capital efficiency in accessing, finding, developing and producing resources, enabled by deep technical capability and a culture of continuous improvement.

Our performance

In Exploration and Production, safety, both personal and process, remains our highest priority. 2009 brought further improvements in personal safety with our reported recordable injury frequency improving from 0.43 in 2008 to 0.39 in 2009. We also achieved improvements in the number of reported process safety-related incidents and a significant reduction in the number of reported spills.

BP s operating management system (OMS) provides us with a systematic framework for safe, reliable and efficient operations. Throughout 2009, OMS helped us to deliver continuous improvement in the way we manage our people, processes, plant and performance.

From onshore production facilities to offshore platforms, a total of 47 exploration and production sites had completed their transition to OMS by the end of 2009. The remaining seven sites are on track to transition to OMS in 2010.

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We continually seek to access resources and in 2009 this included Iraq, where, together with China National Petroleum Corporation (CNPC), we entered into a contract with the state-owned South Oil Company (SOC) to expand production from the Rumaila field; Jordan, where on 3 January 2010, we received approval from the Government of Jordan to join the state-owned National Petroleum Company (NPC) to exploit the onshore Risha concession in the north east of the country; further access in Egypt, where we were awarded two blocks in an offshore area of the Nile Delta; Indonesia, where we signed a production-sharing agreement (PSA) for the exploration and development of coalbed methane in the Sanga-Sanga block, supplying gas to Indonesia s largest LNG export facility and, subject to Government of Indonesia approval, farmed into Chevron s West Papua I & III blocks; and the Gulf of Mexico, where we were awarded 61 blocks through the Outer Continental Shelf Lease Sales 208 and 210.

In 2009, we were involved in a number of discoveries. The most significant of these were in the deepwater Gulf of Mexico with the Tiber well; Angola, where we made three further discoveries in the ultra deepwater Block 31; and Canada, where we discovered natural gas with the Ellice J27 well.

Seven major projects came onstream. We continue to grow our position and leverage our experience as the largest producer in the Gulf of Mexico, starting up three projects ahead of schedule, including the second phase of Atlantis. In addition, production commenced at our Savonette field in Trinidad, at our Tangguh LNG project in Indonesia and, through TNK-BP, we saw the start-up of a further two projects, in the northern hub of Kamennoye, and the Urna and Ust-Tegus fields in the Uvat area.

Production from our established centres including the North Sea, Alaska, North America Gas and Trinidad was on plan, with improved operating efficiency for the segment as a whole, and we had strong production growth in the Gulf of Mexico, including excellent performance from Thunder Horse. Production from Egypt and TNK-BP also made a strong contribution to our growth.

Production for the year was up more than 4% from last year. After adjusting for the effect of entitlement changes in our PSAs and the effect of OPEC quota restrictions, underlying production growth[a] was 5% higher than 2008.

[a] Underlying production growth excludes the effect of entitlement changes in our PSAs (driven by changes in oil and gas prices) and the effect of OPEC quota restrictions.

We also reduced unit production costs through a combination of high-grading activity, improving execution efficiency, capturing the benefits of the deflationary cost environment at the beginning of the year and favourable foreign exchange effects. During 2009 we improved the quality of our procurement and supply chain management organization, systems and processes, which we expect will help deliver sustained cost efficiency in the future.

The replacement cost profit before interest and tax was $24.8 billion, a 35% decrease compared with the record level in 2008. This result was primarily driven by lower oil and gas realizations, lower income from equity-accounted entities and higher depreciation, partly offset by strong underlying production growth and improved cost management, which contributed to a 12% reduction in unit production costs. Our financial results are discussed in more detail on pages 51-52.

Total capital expenditure including acquisitions and asset exchanges in 2009 was $14.9 billion (2008 $22.2 billion and 2007 $14.2 billion). In 2009, capital expenditure included $306 million relating to the award of the contract to redevelop the Rumaila field in Iraq.

Development expenditure of subsidiaries incurred in 2009, excluding midstream activities, was $10,396 million, compared with $11,767 million in 2008 and $10,153 million in 2007.

Key statistics

$ million

	2009	2008	2007
Sales and other operating revenues[a]	**57,626**	86,170	65,740
Replacement cost profit before interest and tax[b]	**24,800**	38,308	27,602
Total assets	**140,149**	136,665	125,736
Capital expenditure and acquisitions	**14,896**	22,227	14,207

			$ per barrel
Average BP liquids realizations[c d]	**56.26**	90.20	67.45

			$ per thousand cubic feet
Average BP natural gas realizations[c]	**3.25**	6.00	4.53

[a] Includes sales between businesses.

[b] Includes profit after interest and tax of equity-accounted entities.

[c] Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.

[d] Crude oil and natural gas liquids.

The table below presents our average sales price per unit of production.

										$ per unit of production[a]
	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Average sales price[b]										
2009										
Liquids[c]	**62.19**	**60.73**	**53.68**	**30.77**	**52.48**	**57.40**		**61.27**	**57.22**	**56.26**
Gas	**4.68**	**7.62**	**3.07**	**3.53**	**2.50**	**3.61**		**3.30**	**5.25**	**3.25**
2008										

Liquids[c]	89.82	93.77	89.22	64.42	91.61	89.44	97.20	86.33	90.20
Gas	8.41	6.96	6.77	7.87	4.90	4.46	3.63	9.22	6.00
2007									
Liquids[c]	69.17	70.41	64.18	48.24	65.54	67.81	73.00	70.56	67.45
Gas	6.40	5.84	5.43	6.24	3.25	3.93	3.05	5.96	4.53

[a]Units of production are barrels for liquids and thousands of cubic feet for gas.

[b]Realizations are based on sales of consolidated subsidiaries only (including transfers between businesses), which excludes equity-accounted entities.

[c]Crude oil and natural gas liquids.

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The table below presents our average production cost per unit of production.

$ per unit of production[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
The average production cost per unit of production[a]										
2009	**12.38**	**10.72**	**7.26**	**14.45**	**2.20**	**6.05**		**4.35**	**1.60**	**6.39**
2008	12.19	8.74	9.02	15.35	2.34	6.72		5.24	1.74	7.24
2007	14.00	7.17	9.03	14.04	2.69	6.43		3.81	1.75	7.14

[a]Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes; and are based on production cost of consolidated subsidiaries only, which excludes equity-accounted entities.

Outlook

Our priorities remain the same safety, people and performance, focusing on the delivery of safe, reliable and efficient operations.

In 2010, we aim to use the momentum generated in 2009 to continue to improve operational, cost and capital efficiency, while ensuring we maintain our priorities of safe, reliable and efficient operations. We intend to continue to focus on building personnel and technological capability for the future. We believe our portfolio of assets is strong and well positioned to compete and grow in a range of external conditions. Also in 2010, we intend to create a centralized developments organization to deliver our major projects. By bringing our project expertise into one team, we expect to continue our drive for improved capital efficiency by fully optimizing our project designs and improving project execution.

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, excluding lease acquisitions, in 2009 were $2,805 million, compared with $2,290 million in 2008 and $1,892 million in 2007. 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 68% of 2009 exploration and appraisal costs were directed towards appraisal activity. In 2009, we participated in 503 gross (107 net) exploration and appraisal wells in 12 countries. The principal areas of exploration and appraisal activity were Angola, Egypt, the deepwater Gulf of Mexico, Libya, the North Sea, Oman and onshore US.

Total exploration expense in 2009 of $1,116 million (2008 $882 million and 2007 $756 million) included the write-off of expenses related to unsuccessful drilling activities in the deepwater Gulf of Mexico ($391 million), India ($31 million), Angola ($28 million), Egypt ($27 million), and others ($31 million).

In most cases, reserves booking from new discoveries will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling.

Reserves and production

Resource progression

BP manages its hydrocarbon resources in three major categories: prospect inventory, contingent resources and proved reserves. When a discovery is made, volumes usually transfer from the prospect inventory to the contingent resources category. The contingent resources move through various sub-categories as their technical and commercial maturity increases through appraisal activity.

At the point of final investment decision, most proved 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 proved reserves depends on a later phase of activity, only that portion of proved reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will typically 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 proved reserves to the start of production. Changes to proved 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.

Contingent resources in a field will only be recategorized as proved reserves when all the criteria for attribution of proved status have been met and the proved reserves are included in the business plan and scheduled for development, typically within five years. Where, on occasion, the group decides to book proved reserves where development is scheduled to commence after five years, these proved reserves will be booked only where they satisfy the SEC s criteria for attribution of proved status. There are material volumes of proved undeveloped reserves in Angola, Trinidad, the US, and Canada which are part of ongoing development activities for which BP has a historical track record of completing comparable projects. In all cases, the volumes are being progressed as part of an adopted development plan which calls for drilling of wells over an extended period of time given the magnitude of the development.

In 2009, we converted approximately 2,061mmboe proved undeveloped reserves to proved developed reserves through ongoing investment in our upstream development activities. Total development expenditure in Exploration and Production, excluding midstream activities, was $12,392 million in 2009 ($10,396 million for subsidiaries and $1,996 million for equity-accounted entities). The major areas converted in 2009 were Azerbaijan, Indonesia, Russia, Trinidad and the US.

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BP bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice. BP only applies technologies that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. BP applies high resolution seismic data for the identification of reservoir extent and fluid contacts only where there is an overwhelming track record of success in its local application. In certain deepwater fields, such as fields in the Gulf of Mexico, BP has booked 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. To determine reasonable certainty of commercial recovery, BP employs a general method of reserves assessment that 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 understanding of 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. There is a strong track record of proved reserves recorded using these methods, validated by actual production levels.

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 proved reserves base undergoes central review every two years and more than 90% is reviewed centrally every four years.

BP s segment resources authority is the petroleum engineer primarily responsible for overseeing the preparation of the reserves estimate. He has over 35 years of diversified industry experience with the past 10 spent as the head of the reservoir management function within BP. He is a member of the Society of Petroleum Engineers (SPE) and the Institute of Materials, Minerals and Mining. On the retirement of the current segment resources authority in 2010, his responsibilities for reserves estimation, governance and compliance will be taken by the current vice president of segment reserves. The current vice president of segment reserves has over 25 years of diversified industry experience with the past seven spent managing the governance and compliance of BP s reserves estimation. He is a sitting member of the SPE Oil and Gas Reserves Committee and the United Nations

Economic Commission for Europe Expert Group on Resource Classification.

For the executive directors and senior management, no specific portion of compensation bonuses is directly related to proved 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. 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 chosen, could relate to proved reserves.

Proved reserves replacement

Total hydrocarbon proved reserves, on an oil equivalent basis including equity-accounted entities, comprised 18,292mmboe (12,621mmboe for subsidiaries and 5,671mmboe for equity-accounted entities) at 31 December 2009, an increase of 0.8% (increase of 0.5% for subsidiaries and increase of 1.5% for equity-accounted entities) compared with 31 December 2008. Natural gas represents about 43% (55% for subsidiaries and 14% for equity-accounted entities) of these reserves. The increase includes a net decrease from acquisitions and divestments of 282mmboe, (59mmboe net decrease for subsidiaries and 223mmboe net decrease for equity-accounted entities) largely comprising a number of assets in Bolivia, Indonesia, Kazakhstan, Pakistan and the UK.

The proved reserves 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. For 2009 the proved reserves replacement ratio excluding acquisitions and divestments was 129% (121% in 2008 and 112% in 2007) for subsidiaries and equity-accounted entities, 112% for subsidiaries alone and 164% for equity-accounted entities alone.

In 2009, net additions to the group s proved reserves (excluding production, sales and purchases of reserves-in-place and equity-accounted entities) amounted to 1,113mmboe (795mmboe for equity-accounted entities), principally through improved recovery from, and extensions to, existing fields and discoveries of new fields. Of our subsidiary reserves additions through improved recovery from, and extensions to, existing fields and discoveries of new fields, approximately 55% are associated with new projects and are proved undeveloped reserves additions. Volumes added in 2009 principally relied on the application of conventional technologies. The remaining additions are in existing developments where they represent a mixture of proved developed and proved undeveloped reserves. The principal reserves additions in our subsidiaries were in the US (Arkoma, Mad Dog, Prudhoe Bay, Thunder Horse), the UK (Clair), Trinidad (Kapok), Angola (Pazflor) and Australia (Jansz-Io). The principal reserves additions in our equity-accounted entities were in Argentina (Cerro Dragon, Cuenca Marina Austral) and in Russia (Kamennoye, Samatlor).

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Compliance

International Financial Reporting Standards (IFRSs) do not provide specific guidance on reserves disclosures. BP estimates proved reserves in accordance with SEC Rule 4-10 (a) of Regulation S-X and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins as issued by the SEC staff. On 31 December 2008, the SEC published a revision of Rule 4-10 (a) of Regulation S-X for the estimation of reserves. These revised rules form the basis of the 2009 year-end estimation of proved reserves and the application of the technical aspects resulted in an immaterial increase of less than 1% to BP s total proved reserves. The reasons for the increase are primarily due to the application of reliable technologies and inclusion of proved reserves more than one spacing away from existing penetrations as discussed below.

By their nature, there is always some risk involved in the ultimate development and production of proved 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, changes in operating and development costs and the continued availability of additional development capital. All the group s proved reserves held in subsidiaries and equity-accounted entities are estimated by the group s petroleum engineers.

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 proved 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 proved 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. Fourteen percent 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 disclose our share of proved 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.

Production

Our total hydrocarbon production during 2009 averaged 3,998 thousand barrels of oil equivalent per day (mboe/d). This comprised 2,684mboe/d for subsidiaries and 1,314mboe/d for equity-accounted entities, an increase of 6.6% and a decrease of 0.5% respectively compared with 2008. For subsidiaries, 40% of our production was in the US, 17% in Trinidad and 10% in the UK. For equity-accounted entities, 71% of production was from Russia, 14% in the United Arab Emirates and 11% in Argentina.

The strong growth in production in 2009 benefited by about 40mboe/d on an annual basis from a combination of the absence of a significant hurricane season and from the make-up of a prior period underlift. As a result, we expect production in 2010 to be slightly lower than in 2009. The actual growth rate will depend on a number of factors, including our pace of capital spending, the efficiency of that spend, the oil price and its impact on PSAs, as well as OPEC quota restrictions.

The group and its equity-accounted entities have numerous long-term sales commitments in their various business activities, all of which are expected to be sourced from supplies available to the group which are not subject to priorities, curtailments or other restrictions. No single contract or group of related contracts is material to the group. The following tables show BP s estimated net proved reserves as at 31 December 2009.

Estimated net proved reserves of liquids at 31 December 2009[a b]

			million barrels
	Developed	Undeveloped	Total

UK	403	291	694
Rest of Europe	83	184	267
US	1,862	1,211	3,073[c]
Rest of North America	11	1	12
South America	49	56	105[d]
Africa	422	454	876
Rest of Asia	182	334	516
Australasia	58	57	115
Subsidiaries	3,070	2,588	5,658
Equity-accounted entities	3,121	1,732	4,853[e]
Total	6,191	4,320	10,511

Estimated net proved reserves of natural gas at 31 December 2009[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	1,602	670	2,272
Rest of Europe	49	397	446
US	9,583	5,633	15,216
Rest of North America	716	453	1,169
South America	3,177	7,393	10,570[f]
Africa	1,107	1,454	2,561
Rest of Asia	1,579	249	1,828
Australasia	3,219	3,107	6,326
Subsidiaries	21,032	19,356	40,388
Equity-accounted entities	3,035	1,707	4,742[g]
Total	24,067	21,063	45,130

Net proved reserves on an oil equivalent basis

			million barrels of oil equivalent
	Developed	Undeveloped	Total
Subsidiaries	6,696	5,925	12,621
Equity-accounted entities	3,644	2,027	5,671
Total	10,340	7,952	18,292

[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

jointly controlled entities 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] The 2009 marker prices used were Brent $59.91/bbl (2008 $36.55/bbl and 2007 $96.02/bbl) and Henry Hub $3.82/mmBtu (2008 $5.63/mmBtu and 2007 $7.10/mmBtu).

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 68 million barrels on which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[d] Includes 23 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[e] Includes 243 million barrels of crude oil in respect of the 6.86% minority interest in TNK-BP.

[f] Includes 3,068 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[g] Includes 131 billion cubic feet of natural gas in respect of the 5.79% minority interest in TNK-BP.

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The following tables show BP s net production by major field for 2009, 2008 and 2007.
Liquids

		thousand barrels per day		
		BP net share of production[a]		
	Field or area	**2009**	2008	2007
UK[b]	ETAP[c]	**34**	27	32
	Foinaven[d]	**29**	26	37
	Other	**105**	120	132
Total UK		**168**	173	201
Norway	Various	**40**	43	51
Total Rest of Europe		**40**	43	51
Total Europe		**208**	216	252
Alaska	Prudhoe Bay[d]	**69**	72	74
	Kuparuk	**45**	48	52
	Milne Point[d]	**24**	27	28
	Other	**43**	50	55
Total Alaska		**181**	197	209
Lower 48 onshore[b]	Various	**97**	97	108
Gulf of Mexico deepwater	Thunder Horse[d]	**133**	24	
	Atlantis[d]	**54**	42	2
	Mad Dog[d]	**35**	31	25
	Mars	**29**	28	30
	Na Kika[d]	**27**	29	32
	Horn Mountain[d]	**25**	18	18
	King[d]	**22**	23	22
	Other	**62**	49	67
Total Gulf of Mexico deepwater		**387**	244	196
Total US		**665**	538	513
Canada[b]	Various[d]	**8**	9	8
Total Rest of North America		**8**	9	8

Total North America		**673**	547	521
Colombia	Various[d]	**23**	24	28
Trinidad & Tobago	Various[d]	**38**	38	30
Venezuela[b]	Various		4	16
Total South America		**61**	66	74
Angola	Greater Plutonio[d]	**70**	69	12
	Kizomba C Dev	**43**	30	
	Dalia	**32**	34	31
	Girassol FPSO	**22**	22	20
	Other	**44**	46	77
Total Angola		**211**	201	140
Egypt	Gupco	**55**	41	36
	Other	**16**	16	7
Total Egypt		**71**	57	43
Algeria	Various	**22**	19	12
Total Africa		**304**	277	195
Azerbaijan	Azeri-Chirag-Gunashli[d]	**94**	97	200
	Other	**7**	8	5
Total Azerbaijan		**101**	105	205
Western Indonesia[b]	Various	**5**	7	7
Other	Various	**17**	16	16
Total Rest of Asia[b]		**123**	128	228
Total Asia		**123**	128	228
Australia	Various	**31**	29	34
Total Australasia		**31**	29	34
Total subsidiaries[e]		**1,400**	1,263	1,304
Equity-accounted entities (BP share)				
Russia TNK-BP[b]	Various	**840**	826	832
Total Russia		**840**	826	832
Abu Dhabi[f]	Various	**182**	210	192

Other	Various	**12**	10	9
Total Rest of Asia[b]		**194**	220	201
Total Asia		**1,034**	1,046	1,033
Argentina	Various	**75**	70	69
Venezuela[b]	Various	**25**	19	6
Bolivia[b]	Various	**1**	3	2
Total South America		**101**	92	77
Total equity-accounted entities		**1,135**	1,138	1,110
Total subsidiaries and equity-accounted entities		**2,535**	2,401	2,414

[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 2009, BP assumed operatorship of the Mirpurkhas and Khipro blocks in Pakistan, swapped a number of assets with BG Group plc in the UK sector of the North Sea, divested some minor interests in the US Lower 48, divested its holdings in Indonesia s Offshore Northwest Java to Pertamina, divested its interests in LukArco to Lukoil and the Bolivian government nationalized, with compensation payable, Pan American Energy s shares of Chaco. In 2008, BP concluded the migration of the Cerro Negro operations to an incorporated joint venture with PDVSA while retaining its equity position and TNK-BP disposed of some non-core interests. 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.

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

[d]BP-operated.

[e]Includes 26 net mboe/d of NGLs from processing plants in which BP has an interest (2008 19mboe/d and 2007 54mboe/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 we report production and reserves there gross of production taxes.

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Natural gas

				million cubic feet per day
			BP net share of production[a]	
	Field or area	**2009**	2008	2007
UK[b]	Bruce/Rhum[c]	**110**	165	161
	Brae East	**62**	71	60
	Other	**446**	523	547
Total UK		**618**	759	768
Netherlands[b]	Various			3
Norway	Various	**16**	23	26
Total Rest of Europe		**16**	23	29
Total Europe		**634**	782	797
Lower 48 onshore[b]	San Juan[c]	**659**	682	694
	Jonah[c]	**227**	221	173
	Arkoma[c]	**194**	240	204
	Wamsutter[c]	**146**	136	120
	Hugoton[c]	**102**	91	123
	Tuscaloosa[c]	**65**	65	78
	Other	**562**	451	458
Total Lower 48 onshore		**1,955**	1,886	1,850
Gulf of Mexico deepwater	Thunder Horse[c]	**83**	11	
	Other	**220**	219	269
Total Gulf of Mexico deepwater		**303**	230	269
Alaska	Various	**58**	41	55
Total US		**2,316**	2,157	2,174
Canada[b]	West Central	**69**	63	63
	Other[c]	**194**	182	192
Total Canada		**263**	245	255

Total Rest of North America		**263**	245	255
Total North America		**2,579**	2,402	2,429
Trinidad & Tobago	Mango[c]	**664**	471	22
	Cashima/NEQB[c]	**571**	375	6
	Kapok[c]	**540**	619	984
	Cannonball[c]	**225**	336	628
	Amherstia[c]	**197**	288	155
	Other[c]	**233**	357	638
Total Trinidad		**2,430**	2,446	2,433
Colombia	Various	**62**	84	104
Venezuela[b]	Various		2	6
Total South America		**2,492**	2,532	2,543
Egypt	Temsah	**118**	109	118
	Happy[c]	**94**	94	108
	Taurt[c]	**73**	24	
	Other	**177**	145	89
Total Egypt		**462**	372	315
Algeria	Various	**159**	112	153
Total Africa		**621**	484	468
Pakistan[b]	Various[c]	**173**	162	121
Azerbaijan	Various[c]	**126**	143	73
Western Indonesia[b]	Sanga-Sanga	**71**	69	75
	Other	**35**	97	81
Total Western Indonesia		**106**	166	156
China	Yacheng	**83**	91	85
Vietnam	Various[c]	**63**	61	82
Sharjah	Various[c]	**59**	73	92
Total Rest of Asia		**610**	696	609
Total Asia		**610**	696	609
Australia	Perseus/Athena	**142**	229	193
	Goodwyn	**139**	74	107
	Angel	**120**	6	
	Other	**39**	71	76

Total Australia		**440**	380	376
Eastern Indonesia	Tangguh[c]	**74**	1	
Total Australasia		**514**	381	376
Total subsidiaries[d]		**7,450**	7,277	7,222
Equity-accounted entities (BP share)				
Russia TNK-BP[b]	Various	**601**	564	451
Total Russia		**601**	564	451
Western Indonesia	Various	**31**	31	33
Kazakhstan[b]	Various	**11**	8	8
Total Rest of Asia		**42**	39	41
Total Asia		**643**	603	492
Argentina	Various	**378**	385	369
Bolivia[b]	Various	**11**	63	60
Venezuela[b]	Various	**3**	6	
Total South America		**392**	454	429
Total equity-accounted entities[d]		**1,035**	1,057	921
Total subsidiaries and equity-accounted entities		**8,485**	8,334	8,143

[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 2009, BP assumed operatorship of the Mirpurkhas and Khipro blocks in Pakistan, swapped a number of assets with BG Group plc in the UK sector of the North Sea, divested some minor interests in the US Lower 48, divested its holdings in Indonesia s Offshore Northwest Java to Pertamina, divested its interests in LukArco to Lukoil and the Bolivian government nationalized, with compensation payable, Pan American Energy s shares of Chaco. In 2008, BP concluded the migration of the Cerro Negro operations to an incorporated joint venture with PDVSA while retaining its equity position and TNK-BP disposed of some non-core interests. 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.

[c]BP-operated.

[d]Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field, but the related reserves are included in the group s reserves.

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Business review

The following narrative reviews operations in our Exploration and Production business by continent and country, and lists associated significant events that occurred in 2009. Where relevant, BP s percentage working interest in oil and gas assets is shown in brackets. Working interest is the cost-bearing ownership share of an oil or gas lease. The percentages disclosed for certain agreements do not necessarily reflect the percentage interests in reserves and production.

North America

United States

Our activities within the US take place in three main areas: deepwater Gulf of Mexico, Lower 48 states and Alaska.

Deepwater Gulf of Mexico:

Deepwater Gulf of Mexico is our largest area of growth in the US. In addition, we are the largest producer and acreage holder in the region.

Significant events were:

In May 2009, BP announced it had begun production from the Dorado (BP 75% and operator) and King South (BP 100%) projects. Both projects are subsea tiebacks to the existing BP Marlin Tension Leg Platform (TLP) infrastructure. Dorado comprises three new subsea wells located about two miles from the Marlin TLP. King South comprises a single subsea well located 18 miles from the Marlin TLP. Both projects leverage existing subsea and topsides infrastructure and the latest subsea and drilling technology to enable the efficient development of the fields. Dorado utilizes dual completion technology enabling production from five Miocene zones and King South is produced through the existing King subsea pump.

In June 2009, the Atlantis Phase 2 (BP 56%) project achieved first oil ahead of schedule, signalling the official start-up.

In July 2009, BP announced the drilling of a successful appraisal well in a previously untested southern segment of the Mad Dog field (BP 60.5% and operator). The 826-5 well is located in the Green Canyon block 826, approximately 100 miles south of Grand Isle, Louisiana, in about 5,100 feet of water. The results from this well continue the successful phased development of the Mad Dog field and build upon the success from 2008.

In September 2009, BP announced the Tiber discovery in the deepwater Gulf of Mexico (BP 62% and operator). The discovery well, located in Keathley Canyon block 102, approximately 250 miles south-east of Houston, is in 4,132 feet of water. It was drilled to a total depth of approximately 35,055 feet making it the deepest oil and gas discovery well ever drilled. The well found oil in multiple Lower Tertiary reservoirs. Appraisal will be required to determine the size and commerciality of the discovery.

Lower 48 states:

Our North America Gas business operates onshore in the Lower 48 states producing natural gas, natural gas liquids and coalbed methane across 14 states. In 2009, we drilled almost 300 wells as operator and continued to maintain a stable programme of drilling activity throughout the year. Shale gas assets are becoming an increasingly important part of our North America Gas business:

Significant events were:

In the fourth quarter of 2009, BP further expanded its shale gas portfolio by securing new access in the Eagle Ford Shale in South Texas. Combined with our 2008 acquisitions of interests in Chesapeake Energy Corporation s Woodford and Fayetteville Shale assets in the Arkoma Basin and our incumbent position in the Haynesville Shale in East Texas, BP now has a material shale gas position in the Lower 48 states.

Since taking over operations of the Woodford shale properties, BP gross operated production has increased from 60mmcf/d in November 2008 to over 100mmcf/d by the end of 2009, a 67% increase. BP delivered 23 wells by the end of the year with an
average 30-day rate of 4.6mmcf/d per well, approximately 50% higher than initial expectations.

In 2009, BP net production from the Fayetteville shale properties has grown from approximately 55mmcf/d to 87mmcf/d at the end of the year, an increase of approximately 60%. Individual well performance continues to exceed expectations by approximately 25%.

In 2009, BP drilled four wells appraising the Haynesville Shale asset and plans to increase horizontal well drilling in 2010. BP s position in the Haynesville Shale in North Louisiana and East Texas covers an area of approximately 150,000 net acres.

The business has made good progress in restructuring its activity and driving down costs to a level that is consistent with the economic environment.

Alaska:

BP operates 15 North Slope oil fields (including Prudhoe Bay, Endicott, Northstar, and Milne Point) and four North Slope pipelines, and owns a significant interest in six other producing fields.

Two key aspects of BP s business strategy in Alaska are commercializing the large undeveloped natural gas resource within our 26.4% interest in Prudhoe Bay and unlocking the large undeveloped heavy oil resources within existing North Slope fields through the application of advanced technology.

Significant events were:

In 2009, we progressed the previously announced development activities for the Liberty oilfield, which is located on federal leases about six miles offshore in the Beaufort Sea, and east of the Prudhoe Bay oilfield. The planned development includes up to six ultra-extended reach wells, including four producers and two injectors, to be drilled from existing infrastructure in the BP-operated Endicott field to minimize the onshore and offshore environmental footprint. These wells are expected to be the longest horizontal wells ever drilled and completed in the industry, extending two miles deep and as far as eight miles horizontally. A specialized rig for drilling in the Arctic has been built for the project, and it is the world s largest and most powerful onshore drilling rig. Key project milestones achieved during 2009 include expansion of the BP-operated Endicott field satellite drilling island (SDI) in April; and sealift delivery of the ultra-extended reach drilling rig to the Endicott SDI in August. Drilling is expected to start in 2010, with first oil expected in 2011. BP drilled the Liberty discovery well in 1997, and is the operator and sole owner of the field.

On 27 January 2009, the Commissioner of the State of Alaska Department of Natural Resources (DNR) issued a Conditional Interim Decision in connection with the appeal of the Point Thomson area lease terminations. The Point Thomson Unit (PTU) was terminated by administrative decision of the DNR in November 2006 (BP 32%). In February 2007, the DNR notified the PTU owners of its decision to terminate the Point Thomson area leases as well. ExxonMobil, operator, and the other unit owners including BP, are pursuing an appeal of the unit termination in the Alaska Superior Court; and the lease terminations are under administrative appeal with the DNR. The 27 January 2009 Conditional Interim Decision permitted ExxonMobil to conduct drilling operations on two of the 31 terminated leases comprising the former PTU. The DNR s interim decision provided that the two leases would be reinstated if certain conditions were met. On 11 January 2010, the Alaska Superior Court reversed the DNR Commissioner s administrative decision to terminate the PTU. The parties have been ordered to provide the Court further briefing regarding whether the Court should again remand the matter for an administrative proceeding with DNR, or retain jurisdiction with the Alaska Superior Court and conduct a de novo proceeding.

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Canada

In Canada, BP operates in five provinces and two territories, exploring for, developing, producing and processing natural gas and heavy crude oil. We also hold an interest in an oil sands joint venture with Husky Energy Inc., we market natural gas and we are the largest marketer of natural gas liquids.

In 2009, BP conducted a successful 3D seismic programme over the primary area of interest on the exploration licences acquired in 2008 in the Canadian Beaufort Sea. The programme was the most northerly 3D seismic programme ever conducted, with approximately 1,600 square kilometres of 3D data acquired. The project also had the largest array of towed marine streamers deployed in the high Arctic. BP has 2,392,101 acres (968,049 hectares) of significant discovery licences and exploration licences in the Beaufort Sea.

South America

Venezuela

BP has been in Venezuela since 1994 and currently participates in three equity-accounted entities.

In 2009, production cuts due to OPEC quota restrictions were assigned to the Petromonagas and Petroperija entities. Petromonagas s OPEC quota restrictions resulted in a complete production shutdown until 12 July 2009. There is uncertainty regarding the duration of the quota restrictions in Petroperija.

Colombia

Our main activity in Colombia is concentrated on operating a producing field complex in the Casanare region. In addition, we operate four principal processing plants and own pipeline interests. BP also holds exploration rights over two blocks off Colombia s northern coast in the Caribbean Sea.

During 2009, seismic data processing and interpretation was carried out at the RC4 and RC5 Caribbean offshore blocks (BP 40.6%) in order to determine potential prospects. A decision whether to drill a well is expected to be taken in 2010.

During 2009, the strategy and detailed plan for the termination of the Santiago de las Atalayas field contract by June 2010, and its subsequent operation by Ecopetrol, was designed and implemented.

Argentina, Bolivia and Chile

BP conducts activity in the Southern Cone region of South America (Argentina, Bolivia and Chile) through Pan American Energy (PAE), a joint venture company in which BP holds a 60% interest. As the venture is jointly controlled with Bridas Corporation, it is accounted for using the equity method of accounting. Most of the PAE production comes from the Cerro Dragon field in the provinces of Chubut and Santa Cruz.

The Cerro Dragon field is now producing at its highest level since the licence was granted in 1958, and further expansion programmes are planned. PAE also has other gas and liquids producing assets in the Argentine provinces of Salta, Neuquen and Tierra del Fuego, and in Bolivia. PAE also has interests in exploration areas, pipelines, and other midstream infrastructure assets, primarily in Argentina.

On 26 November 2008, the Argentine government issued a decree by which a new regime on oil and by-products exports, called Petróleo Plus was put in place. This programme provides fiscal relief in the form of fiscal credit certificates, which can be used to offset export tariffs on oil, LPG and by-products. The goal is to incentivize investment to increase oil production and reserves. As PAE achieved the targets for both reserves replacement and production growth stipulated in the programme, it has obtained and applied fiscal credit certificates since January 2009.

On 23 January 2009, the president of Bolivia issued a decree nationalizing PAE s investment in 8,049,660 shares of Chaco. The decree establishes a compensation value per share, which represents a total amount of $233 million (BP share $140 million), subject to eventual adjustments. The partners assert that this is not an adequate compensation for the nationalized shares. PAE will pursue an adequate compensation for the nationalized assets.

On 28 January and 22 May 2009, PAE entered into two agreements with the Neuquen province in Argentina that provide for the extension of concession terms related to the exploration and development of the Aguada Pichana and San Roque blocks and of the Lindero Atravesado block, respectively.

Trinidad & Tobago

BP holds exploration and production licences covering 904,000 acres offshore of the east coast. Facilities include 12 offshore platforms and one onshore processing facility. Production is comprised of oil, gas and NGLs.

On 27 October 2009, the Savonette offshore field development began production on a normally unmanned installation platform (NUI). Savonette is located in 290 feet (88 metres) of water approximately 50 miles off Trinidad s south-east coast. Production from the platform is tied in to BP Trinidad and Tobago s Mahogany B platform and will supply the Trinidad domestic market as well as Atlantic LNG s liquefaction plant for export as LNG to international markets. The Savonette platform, installed in February 2009, is the fourth in a series of NUIs designed and constructed locally in Trinidad using a standardized clone concept. The first three NUIs were Cannonball, Mango and Cashima.

Europe

United Kingdom

We are the largest producer of oil, the second largest producer of gas and the largest overall producer of hydrocarbons in the UK. Key aspects of our activities in the North Sea include a focus on in-field drilling and selected new field developments. Our development expenditure (excluding midstream) in the UK was $751 million in 2009, compared with $907 million in 2008 and $804 million in 2007. BP operates one NGL plant in the UK.

Significant events were:

On 31 August 2009, the exchange of assets between BP and BG Group was formally completed. The exchange is expected to strengthen BP s position as a major operator in the southern North Sea and to facilitate development activity and investment in the UK Continental Shelf. BP acquired BG s 24.2% interest in the BP-operated Amethyst field and all its interests in the Easington Catchment Area fields, including a 73.3% interest in the Mercury field, a 79% interest in the Neptune field, a 65% interest in the Minerva, Apollo and Artemis fields and BG s 30.8% interest in the BP-operated Whittle and Wollaston fields. In return, BG Group acquired BP s interest and operatorship in the Everest (BP 21.1%) and Lomond (BP 22.2%) fields, BP s 18.2% interest in the BG-operated Armada field and 32% of the Chevron-operated Erskine field (BP retained 18% equity in Erskine).

Drilling performance moved from fourth quartile in 2007 to first quartile in 2008[a], and generated additional drilling capital efficiencies in 2009.

[a] Source: BP Drilling and Completions Global Benchmarking.

Business review

Rest of Europe

Our activities in the Rest of Europe are in Norway.

Development expenditure (excluding midstream) in the Rest of Europe was $1,054 million, compared with $695 million in 2008 and $443 million in 2007. Progress continued on the Skarv and Valhall redevelopment projects.

Africa

Angola

BP is present in four major deepwater licences offshore Angola (Blocks 15, 17, 18 and 31) and is operator in Blocks 18 and 31. In addition, BP holds a 13.6% equity share in the first Angolan LNG project. Technical skills developed in similar deepwater basins around the world have been applied extensively in BP s operations in Angola.

On 29 December 2008, BP began a comprehensive seismic survey on Block 31 (BP 26.67% and operator) using a wide azimuth towed streamer (WATS) to gain improved imaging quality of sub-salt strata. WATS seismic is an acquisition configuration developed by BP to image areas of complex geology below salt. The WATS survey will significantly improve the imaging and understanding of the fields, and more significantly, the data acquired will also support the definition of hubs which will form part of BP s development programme. This is the first such survey to be conducted by BP outside the Gulf of Mexico, and is the first WATS survey conducted in Angola.

In 2009, BP announced its seventeenth through nineteenth discoveries in the ultra deepwater Block 31. On 3 March 2009, BP announced the discovery of the Leda field. Leda was drilled in a water depth of 2,070 metres and reached a total depth of nearly 6 kilometres below sea level. It is located in the central northern portion of Block 31, some 415 kilometres north-west of Luanda. This is the fifth discovery in Block 31 in which the exploration well has been drilled through salt to access the oil-bearing sandstone reservoir beneath. On 27 May 2009, BP announced the Oberon oil discovery. Oberon-1 was drilled in a water depth of 1,624 metres and reached a total depth of 3,622 metres below sea level. On 1 October 2009, BP announced the Tebe oil discovery. The Tebe well was drilled in a water depth of 1,752 metres and a total depth of 3,325 metres below sea level.

Algeria

BP is a partner with Sonatrach and Statoil in the In Salah (BP 33.15%) and In Amenas (BP 45.89%) projects, which supply gas to the domestic and European markets. BP is also in partnership with Sonatrach in the Rhourde El Baguel (REB) oilfield (BP 60%), an enhanced oil recovery project 75 kilometres east of the Hassi Messaoud oilfield. In addition, BP is in partnership with Sonatrach in the Bourarhet Sud block, located to the south-west of In Amenas.

In 2008, Sonatrach and BP announced a discovery with the Tin Zaouatene-1 (TZN-1) exploration well. BP is currently in the second prospecting period, which runs until September 2010. Seismic operations started in February 2009 and were completed in October 2009. Drilling activities commenced in December 2009.

Libya

In Libya, BP is in partnership with the Libyan Investment Corporation (LIC) to explore the onshore Ghadames and offshore Sirt basins.

In 2009, BP continued the onshore and offshore seismic operations started in 2008 on the acreage covered under the exploration and production sharing agreement ratified in December 2007 (BP 85%).

In October 2009, BP completed a large offshore 3D survey in the deepwaters of the Libyan Gulf of Sirt. The programme, started in September 2008, was conducted by the seismic vessel *Geowave Endeavour* (operated by CGGV-Wavefield Inseis), and covered 17,000 square kilometres, 60% of BP s Sirt exploration acreage.

BP is also progressing its onshore seismic operations in the deserts of Libya s Ghadames basin. This is the first full application of a new, cutting-edge seismic technique developed by BP, known as Independent Simultaneous Sweeping (ISS): the technology allows greater acquisition (in excess of 10,000 vibration points per day compared with conventional technology of 1,500 per day) and cost efficiency. Exploration drilling is scheduled to commence during 2010 in both onshore and offshore blocks.

Egypt

BP is the single largest foreign investor in Egypt, with investments close to $15 billion to date. With its partners, BP has produced almost 40% of Egypt s entire oil production and close to 30% of its gas production. The Gulf of Suez Petroleum Company (GUPCO), BP s joint venture with the Egyptian General Petroleum Corporation, has been an industry leader in Egypt and the entire region and covers operations in the Gulf of Suez and the Western Desert.

During the second quarter of 2009, BP was awarded two blocks in the Egyptian Offshore Nile Delta. BP has a 100% working interest and is the operator of Block 2, North Tineh, which is in a deepwater area of the Eastern Nile Delta. BP will also be the operator of Block 3, North Damietta Offshore, which is adjacent to Block 2, with Shell and Petronas as partners with a one-third working interest each. These awards build on the existing portfolio in Egypt, providing an additional platform for growth. BP s expertise in exploring deepwater, high-pressure and high-temperature deep targets maximizes the chances of unlocking the potential in this area.

During the third quarter of 2009, the Egyptian parliament approved the amendments to two Gulf of Suez (GOS) concessions: South Belayim (BP 100%) and South Ghara (BP 75%). The amendments provide BP with enhanced commercial structure and extend the term of both concessions by 20 years in return for increased investment levels. This marks a significant step in the development of the Southern GOS assets.

Asia

Western Indonesia

BP has a joint interest in Virginia Indonesia Company LLC (VICO), the operator of the Sanga-Sanga PSA (BP 38%) supplying gas to Indonesia s largest LNG export facility, the Bontang LNG plant in Kalimantan.

During 2009, VICO successfully completed a joint evaluation of the coalbed methane (CBM) opportunities in the Sanga-Sanga area. In November, VICO signed a PSA with the Government of Indonesia, for the exploration and development of these CBM resources.

On 1 July 2009, BP divested its entire 46% holding in the Offshore Northwest Java (ONWJ) PSA to Indonesia s national oil company, Pertamina.

Vietnam

Our upstream business in Vietnam is concentrated on the Block 6.1 offshore gas field. BP participates in one of the country s largest foreign investment projects, the Nam Con Son gas project. This is an integrated resource and infrastructure project, which includes offshore gas production, a pipeline transportation system and a power plant.

BP Block 6.1 Lan Do development project was sanctioned in December 2009, with first gas scheduled in 2012.

BP s withdrawal from Blocks 5.2 (BP 55.9% and operator) and 5.3 (BP 75% and operator) was completed in December 2009.

China

BP s upstream asset in the country is the Yacheng offshore gas field (BP 34.3%) in the South China Sea, one of the biggest offshore gas fields in China. Yacheng supplies the Castle Peak Power Company gas for up to 70% of Hong Kong s gas-fired electricity generation. Additional gas is also sold to the Hainan Holdings Fuel & Chemical Corporation Limited.

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Business review

The Platform A development project approved at the end of 2008 is on track to deliver first gas in 2010.

Azerbaijan

BP is the largest foreign investor in the country. BP operates two PSAs, Azeri-Chirag-Gunashli (ACG) and Shah Deniz, and also holds other exploration leases.

A comprehensive review of the subsurface gas release that occurred beneath the Central Azeri platform in September 2008, and subsequent remedial works, have resulted in bringing the level of production from the platform to over 220mboe/d from 12 wells. Further minor remedial work is planned during 2010.

On 13 July 2009, BP and the State Oil Company of the Republic of Azerbaijan (SOCAR) signed a memorandum of understanding (MOU) to jointly explore and develop the Shafag and Asiman structures in the Azerbaijan sector of the Caspian Sea. The MOU gives BP the exclusive right to negotiate the PSA. The block covers an area of some 1,100 square kilometres and has never been explored before. It is located in a deepwater section of about 650-800 metres with reservoir depth of about 7,000 metres.

Russia

TNK-BP

TNK-BP, an associate owned by BP (50%) and Alfa Group and Access-Renova (AAR) (50%), is an integrated oil company operating in Russia and the Ukraine. BP s investment in TNK-BP is reported in the Exploration and Production segment. The TNK-BP group s major assets are held in OAO TNK-BP Holding. Other assets include the BP-branded retail sites in the Moscow region and interests in OAO Rusia Petroleum and the OAO Slavneft group. The workforce comprises more than 52,000 people.

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 683 thousand barrels per day. TNK-BP supplies approximately 1,400 branded filling stations in Russia and the Ukraine and has more than 20% market share of the Moscow retail market.

On 9 January 2009, BP reached final agreement on amendments to the shareholder agreement with its Russian partners in TNK-BP. The revised agreement is aimed at improving the balance of interests between the company s owners, and focusing the business more explicitly on value growth. The former evenly balanced main board structure has been replaced by one with four representatives each from BP and AAR, plus three independent directors. Unanimous board support is required for certain matters including substantial acquisitions, divestments and contracts, and projects outside the business plan, together with approval of key changes to the TNK-BP group s financial framework and related-party transactions. A number of other matters will be decided by approval of a majority of the board, so that the independent directors will have the ability to decide in the event of disagreement between the shareholder representatives on the board. BP will continue to nominate the chief executive officer (CEO), subject to main board approval, and AAR will continue to appoint the chairman. The three independent directors appointed to the restructured main board are Gerhard Schroeder, former chancellor of the Federal Republic of Germany, James Leng, former chairman of Corus Steel and Alexander Shokhin, president of the Russian Union of Industrialists and Entrepreneurs. In addition, significant TNK-BP subsidiaries will have directors appointed by BP and AAR on their boards. Our investment was reclassified from a jointly controlled entity to an associate with effect from 9 January 2009; however, the results of TNK-BP continue to be accounted for under the equity method. On 6 August 2009, TNK-BP announced that William Schrader was appointed chief operating officer. Mr. Schrader took office during the fourth quarter of 2009, replacing Tim Summers. In November, the TNK-BP board of directors unanimously agreed to
appoint Maxim Barsky, TNK-BP executive vice president for strategy and business development, as the TNK-BP group s future CEO, effective 1 January 2011. Until that time, Mikhail Fridman has agreed to continue to act as interim CEO, in addition to his role as executive chairman of the board of directors of TNK-BP Limited.

On 16 February 2009, TNK-BP announced that the company had launched commercial production from the Urna and Ust-Tegus fields in the Uvat area of the Tyumen region, Russia. Urna and Ust-Tegus are located in the eastern part of Uvat. TNK-BP completed construction of a 264-kilometre pipeline and a central crude oil gathering facility, which facilitate transportation of oil from the fields westwards to enter the Transneft pipeline system. Investment in field development and construction of the infrastructure is expected to amount to over $1.5 billion.

On 2 June 2009, TNK-BP announced that the company had launched commercial production in the Northern Hub of the Kamennoye field, one month earlier than planned. The Kamennoye field, in the Khanty-Mansiisk region of West Siberia, is one of the largest greenfield projects developed by TNK-BP. Aitor and Poima form the Northern Hub of the producing Kamennoye field. Thirty-five wells were drilled and completed in Aitor and, going forward, the primary focus is on drilling 194 wells in Poima. Infrastructure construction includes upgrading of the gathering and treatment facilities, construction and upgrade of the pipeline and water flood systems as well as the power supply system. This strategy and development plan is aimed at maximizing the use of existing facilities and minimizing the impact on the ecologically sensitive territory. Between 2004 and 2009, investment in the Kamennoye project amounted to over $800 million.

On 29 July 2009, TNK-BP and Weatherford International Ltd (Weatherford) announced that TNK-BP completed the sale of its Oil Field Services (OFS) enterprises to Weatherford pursuant to the sales and purchase agreement signed on 29 May 2009. Via this transaction, Weatherford acquired 10 OFS companies providing drilling, well work-over and cementing services operating in West Siberia, East Siberia and the Volga-Urals region.

In 2007, BP and TNK-BP signed heads of agreement to create strategic business alliances with OAO Gazprom. Under the terms of this agreement, TNK-BP agreed to sell to Gazprom its stake in OAO Rusia Petroleum, the company that owns the licence for the Kovykta gas condensate field in East Siberia and its interest in East Siberia Gas Company. Discussions to conclude this disposal continue.

Sakhalin

BP has material interests in Sakhalin through two joint venture companies, Elvary Neftegaz and Vostok Shmidt Neftegaz. BP has a 49% equity interest in each joint venture, and its partner, Rosneft, holds the remaining 51% interest. During the year, both joint ventures, via their Russian affiliates, held Geological and Geophysical Studies licences with the Russian Ministry of Natural Resources (MNR) to perform exploration seismic and drilling operations in these licence areas off the east coast of Russia. To date, 3D seismic data has been acquired in relation to both licences. In the Elvary Neftegaz licence additional 2D and 3D seismic data was acquired during 2009 in preparation for future drilling commitments.

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Kazakhstan

On 11 December 2009, BP announced that it has divested its interest in Kazakhstan s Tengiz oil field and the Caspian Pipeline Consortium (CPC) pipeline, carrying oil between Kazakhstan and Russia, by selling its 46% stake in LukArco to Russia s Lukoil. Lukoil, which already owns 54% of LukArco, will pay $1.6 billion in cash in three instalments over two years from December 2009.

Middle East and Pakistan

Production in the Middle East consists principally of the production entitlement of associates in Abu Dhabi, where we have equity interests of 9.5% and 14.67% in onshore and offshore concessions respectively.

In Sharjah, the joint agreement between BP, the Government of Sharjah, Itochu and Tokyo Beki, for the operation and maintenance of LPG facilities and the production and marketing of LPG products, expired on 22 March 2009 after a period of 25 years. BP relinquished its 25% ownership, in accordance with the joint venture agreement, and negotiated terms that retain BP as the operator of the facilities through an operating fee structure.

In Block 61 in Oman, the challenges posed by the world s largest onshore wide-azimuth 3D seismic survey led the BP Oman team to use a ground-breaking new technique known as distance separated simultaneous sweeping (DS3). BP s appraisal programme continues to make good progress evaluating the resources in place in the Khazzan/Makarem gas fields. Five appraisal wells have been drilled in 2009. Fracture stimulation and testing of these wells continues. Infrastructure to facilitate long-term wells tests is under construction and expected to be ready for service in the second half of 2010.

On 3 January 2010, we received approval from the Government of Jordan to join the state-owned National Petroleum Company to exploit the onshore Risha concession in the north-east of the country.

With effect from 1 January 2009 BP assumed operatorship of the Mirpurkhas and Khipro onshore blocks in the southern Sindh province of Pakistan.

In the third quarter of 2009, BP won bids for two new exploration blocks, Digri and Sanghar South, in Pakistan. These blocks are adjacent to BP s Mirpurkhas and Khipro concession areas and add another 5,000 square kilometres to the group s existing portfolio of 5,300 square kilometres. BP has committed to invest approximately $30 million in these blocks for seismic and wells over the next three years.

Iraq

In November 2009, BP and China National Petroleum Company (CNPC) entered into a contract with the state-owned Southern Oil Company of Iraq to expand production from the Rumaila oilfield near Basra in southern Iraq. This followed a successful bid for the contract in Baghdad in June 2009. The Rumaila field currently produces approximately one million barrels of oil per day. BP and CNPC plan to invest approximately $15 billion over the next 20 years to enhance the Rumaila production to a plateau rate of 2.85mmb/d, around 3% of global oil production. BP will hold a 38% working interest, CNPC will hold 37% and the remaining 25% will be held by the State Oil Marketing Organisation (SOMO) representing the Iraqi government.

Australasia

Australia

BP is one of seven partners in the North West Shelf (NWS) venture. Six partners (including BP) hold an equal 16.67% 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 NWS venture is currently the principal supplier to the domestic market in Western Australia and one of the largest LNG export projects in Asia with five LNG trains in operation.

The North Rankin 2 project linking a second platform to the existing North Rankin A platform sanctioned in 2008, is on schedule. On completion, the North Rankin A and North Rankin B platforms will operate as a single integrated facility and recover low pressure gas from the North Rankin and Perseus gas fields.

The joint venture partners (Chevron, ExxonMobil and Shell) approved the Greater Gorgon project on 14 September 2009 with the Australian Government also awarding production licences for the Jansz-Io field (BP 5.375%). The Jansz-Io field will be developed as part of the Greater Gorgon project, which will comprise three LNG trains, each with a capacity of 5 million tonnes per annum (mtpa), on Barrow Island with first gas expected in 2014. As part of this, a unitization and unit operating agreement has been executed with the joint venture partners and sales and purchase agreements for the wellhead sale of raw gas and repurchase of LNG ex-Barrow Island have been executed between BP and Shell.

Midstream activities

Oil and natural gas transportation

The group has direct or indirect interests in certain crude oil and natural gas transportation systems. The following narrative details the significant events that occurred during 2009 by country.

BP s onshore US crude oil and product pipelines and related transportation assets are included under Refining and Marketing (*see page 32*).

Alaska

BP owns a 46.9% interest in the Trans-Alaska Pipeline System (TAPS), with the balance owned by four other companies. BP also owns a 50% interest in a joint venture company called Denali The Alaska Gas Pipeline (Denali). Denali has begun work on an Alaska gas pipeline project, consisting of a gas treatment plant on Alaska s North Slope, a large diameter pipeline that is intended to pass through Alaska into Canada, and should it be required, a large-diameter pipeline from Alberta to the Lower 48 states. When completed, the pipeline is expected to transport approximately 4 billion cubic feet of natural gas per day to market. Following a successful open season, Denali will seek certification from the Federal Energy Regulatory Commission (FERC) of the US and the National Energy Board (NEB) of Canada to move forward with project construction. Denali will manage the project, and will own and operate the pipeline when completed. BP may consider other equity partners, including pipeline companies, who can add value to the project and help manage the risks involved.

Significant events were:

Work on the strategic reconfiguration project to upgrade and automate four TAPS pump stations continued to progress in 2009. This project involves installing electrically driven pumps at four critical pump stations, along with increased automation and upgraded control systems. Two of the reconfigured pump stations came online during 2007 and a third reconfigured pump station came online in May 2009. Reconfiguration of the remaining pump station in the programme plan will commence in 2010, with installation currently planned for 2012.

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On 16 April 2009, the US FERC issued an initial ruling on shipper challenges of TAPS interstate tariff rates for the years 2007 and 2008, ordering interim refunds to be paid to shippers based on the January 2009 tariff rate filings. As a result of this order, BP, as a TAPS carrier, paid refunds of $7.3 million to third-party shippers covering the period from 1 January 2007 to 30 June 2009, based on its January 2009 tariff rate filing of $3.45/bbl. Shippers had also filed challenges of the TAPS carriers 2009 interstate tariff rates, based on the FERC rulings issued related to 2005 through 2008 tariff rates. On 12 January 2010, an agreement to settle all remaining challenges to TAPS carrier interstate tariff rate filings for the years 2008 and the first half of 2009 was signed by all the TAPS carriers and shippers. Under the terms of the settlement, BP will pay additional refunds to third-party shippers for the period from January 2007 through June 2009 of $0.12/bbl, representing the difference between the $3.45/bbl tariff rate on which the interim refunds for this period were based, and the $3.33/bbl tariff rate in the settlement agreement. The signed settlement agreement has been submitted to the FERC for final regulatory approval. In 2009, interstate transport represented approximately 90% of total TAPS throughput.

North Sea

In the UK sector of the North Sea, BP operates the Forties Pipeline System (FPS) (BP 100%), 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 one million barrels per day, with average throughput in 2009 of 671mb/d. BP also operates and has a 29.5% interest in the Central Area Transmission System (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 addition, BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe oil and gas terminal in Shetland.

Asia

BP, as operator, manages and holds a 30.1% interest in the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. The 1,768-kilometre pipeline transports oil from the BP-operated ACG oil field in the Caspian Sea to the eastern Mediterranean port of Ceyhan. BP is technical operator of, and holds a 25.5% interest in, the 693-kilometre South Caucasus Pipeline (SCP), which takes gas from Azerbaijan through Georgia to the Turkish border. In addition, BP operates the Azerbaijan section of the Western Export Route Pipeline between Azerbaijan and the Black Sea coast of Georgia (as operator of Azerbaijan International Operating Company).

Significant events were:

On 23 April 2009, BP completed the sale of its 49.9% interest in Kazakhstan Pipeline Ventures (KPV) to Kazakhstan state oil and gas company KazMunayGas (KMG) for $250 million. KPV holds a 1.75% interest in the Caspian Pipeline Consortium (CPC) that carries crude oil from Kazakhstan s largest producing oil field, Tengiz, to the Russian port of Novorossiysk on the Black Sea.

On 11 December 2009, BP also divested its interest in the CPC pipeline (held through LukArco) by selling its 46% stake in LukArco to Lukoil.

Liquefied natural gas

Our LNG activities are focused on building competitively advantaged liquefaction projects, establishing diversified market positions to create maximum value for our upstream natural gas resources and capturing third-party LNG supply to complement our equity flows.

Assets and significant events included:

In Trinidad, BP s net share of the capacity of Atlantic LNG Trains 1, 2, 3 and 4 is 6 million tonnes of LNG per year (369 billion cubic feet equivalent regasified), with the Atlantic LNG Train 4 (BP 37.8%) designed to produce 5.2mtpa (294 billion cubic feet per annum) of LNG. All of the LNG from Atlantic Train 1 and most of the LNG from Trains 2 and 3 is sold to third parties in the US and Spain under long-term contracts. All of BP s LNG entitlement from Atlantic LNG Train 4 and some of its LNG entitlement from Trains 2 and 3 is marketed via BP s LNG marketing and trading business to a variety of markets including the US, the Dominican Republic, Spain, the UK and the Far East.

We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2009 supplied 5.4 million tonnes (279,000mmcf) of LNG.

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 to produce 5.2 million tonnes per year of LNG (gross), as well as related gas liquids products. Construction and implementation of the project is proceeding and is expected to start up in 2012.

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 13% of the total gas feed to Bontang, one of the world s largest LNG plants. The Bontang plant produced more than 17 million tonnes of LNG in 2009.

Also in Indonesia, the Tangguh project (BP 37.16% and operator) in Papua Barat, Indonesia, started LNG production in June 2009, delivering its first commercial LNG delivery in July. Tangguh is BP s first operated LNG plant. The first phase of Tangguh comprises two offshore platforms, two pipelines and an LNG plant with two production trains with a total capacity of 7.6mtpa. Tangguh adopted a fully integrated approach to development and its impact on local communities. The Tangguh project has five long-term contracts in place to supply LNG to purchasers in China, South Korea, Mexico and Japan.

In Australia, we are one of seven partners in the North West Shelf (NWS) venture. The joint venture operation covers offshore production platforms, trunklines, onshore gas and LNG processing plants and LNG carriers. BP s net share of the capacity of NWS LNG Trains 1-5 is 2.7mtpa of LNG.

BP has a 30% equity stake in the 7mtpa capacity Guangdong LNG regasification and pipeline project in south-east China, making it the only foreign partner in China s LNG import business. The terminal is also supplied under a long-term contract with Australia s NWS project.

In both the Atlantic and Asian regions, BP is marketing LNG using BP LNG shipping and contractual rights to access import terminal capacity in the liquid markets of the US (via Cove Point and Elba Island), the UK (via the Isle of Grain) and Italy (Rovigo), and is supplying Asian customers in Japan, South Korea and Taiwan.

Business review

Gas marketing and trading activities

Gas and power marketing and trading activity is undertaken primarily in the US, Canada and Europe to market both BP production and third-party natural gas, support LNG activities and manage market price risk as well as to create incremental trading opportunities through the use of commodity derivative contracts. Additionally, this activity generates fee income and enhanced margins from sources such as the management of price risk on behalf of third-party customers. These markets are large, liquid and volatile.

In connection with the above activities, the group uses a range of commodity derivative contracts and storage and transport contracts. These include commodity derivatives such as futures, swaps and options to manage price risk and forward contracts used to buy and sell gas and power in the marketplace. Using these contracts, in combination with rights to access storage and transportation capacity, allows the group to access advantageous pricing differences between locations, time periods and arbitrage between markets. Natural gas futures and options are traded through exchanges, while over-the-counter (OTC) options and swaps are used for both gas and power transactions through bilateral and/or centrally cleared arrangements. Futures and options are primarily used to trade the key index prices such as Henry Hub, while swaps can be tailored to price with reference to specific delivery locations where gas and power can be bought and sold. OTC forward contracts have evolved in both the US and UK markets, enabling gas and power to be sold forward in a variety of locations and future periods. These contracts are used both to sell production into the wholesale markets and as trading instruments to buy and sell gas and power in future periods. Storage and transportation contracts allow the group to store and transport gas, and transmit power between these locations. The group has developed a risk governance framework to manage and oversee the financial risks associated with this trading activity, which is described in Note 24 to the Financial statements on pages 142-147.

The range of contracts that the group enters into is described below in more detail.

Exchange-traded commodity derivatives

Exchange-traded commodity derivatives include gas and power futures contracts. Though potentially settled physically, these contracts are typically settled financially. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant exchange. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

OTC contracts

These contracts are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties; others may be cleared by a central clearing counterparty. These contracts can be used for both trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in sales and other operating revenues for accounting purposes. Highly developed markets exist in North America and the UK where gas and power can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price, with delivery and settlement at a future date. Typically, these contracts specify delivery terms for the underlying commodity. Certain of these transactions are not settled physically. This can be achieved by transacting offsetting sale or purchase contracts for the same location and delivery period that are offset during the scheduling of delivery or dispatch. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically, volume and price are the main variable terms. Swaps can be contractual obligations to exchange cash flows between two parties. One usually references a floating price and the other a fixed price, with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell natural gas products or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry, typically through netting agreements to limit credit exposure and support liquidity.

Spot and term contracts

Spot contracts are contracts to purchase or sell a commodity at the market price, typically an index price prevailing on the delivery date when title to the inventory passes. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. These transactions result in physical delivery with operational and price risk. Spot and term contracts relate typically to purchases of third-party gas and sales of the group s gas production to third parties. For accounting purposes, spot and term sales are included in sales and other operating revenues, when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.

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Business review

Refining and Marketing

Our Refining and Marketing business is responsible for the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers. BP markets its products in more than 80 countries. We have significant operations in Europe and North America and also manufacture and market our products across Australasia, in China and other parts of Asia, Africa and Central and South America.

Our organization is managed through two main business groupings: fuels value chains (FVCs) and international businesses (IBs). The FVCs integrate the activities of refining, logistics, marketing, supply and trading, on a regional basis, recognizing the geographic nature of the markets in which we compete. This provides the opportunity to optimize our activities from crude oil purchases to end-consumer sales through our physical assets (refineries, terminals, pipelines and retail stations). The IBs include the manufacturing, supply and marketing of lubricants, petrochemicals, aviation fuels and liquefied petroleum gas (LPG).

Our market

The 2009 operating environment was again challenging. Global oil demand contracted by approximately 1.3 million barrels per day with demand in the OECD falling for the fourth consecutive year. Crude oil prices more than doubled during the course of the year, from a dated Brent price of $36.55 per barrel on 1 January 2009 to $77.67 per barrel at the end of 2009, contributing to margin volatility.

Refining margins fell sharply in 2009 as demand for oil products reduced in the wake of the global economic recession and new refining capacity came onstream, mostly in Asia. During 2009, distillate inventories were consistently above the top of the range of the past five years. Gasoline inventories grew steadily and were generally at or slightly above the average level of the past five years. As a result, the BP global indicator refining margin (GIM) averaged $4 per barrel in 2009, down $2.50 per barrel compared with 2008, with the average for the fourth-quarter of 2009 at only $1.49 per barrel, the lowest for almost 15 years. This margin decline had a significant adverse impact on the financial performance of the segment.

In Europe, where diesel accounts for a large proportion of regional demand, refining margins were hit by reduced demand from commercial transport because of the economic recession. In the US, where refining is more highly upgraded and the transport market is more gasoline oriented, margins deteriorated less. Refining margins in Asia Pacific were the hardest hit due to substantial additions to refining capacity in the region.

During 2009, upgrading margins were particularly poor due to stronger relative fuel oil prices and narrow light-heavy crude spreads. This adversely impacted our highly upgraded refineries and had an adverse impact on our financial performance in 2009 compared with 2008.

The end of 2008 and the first quarter of 2009 saw unprecedented levels of market volatility, driven by turmoil in the financial sector and disruptions in the supply chain resulting from the economic downturn. This high level of volatility, combined with our proprietary asset base and trading skills, enabled us to deliver a particularly strong supply and trading result in the first quarter of 2009. Subsequent to the first quarter, volatility returned to more normal levels.

In our IBs, we saw a decline in demand for lubricants due to the financial crisis. During the year we saw a partial recovery in the demand for our petrochemicals products.

Our strategy

Our purpose is to be the product- and service-led arm of BP, focused on fuels, lubricants, petrochemicals products and related services. We aim to be excellent in the markets we choose to be in those that allow BP to serve the major energy markets of the world. We are in pursuit of competitive returns and enduring growth, as we serve customers and promote BP and our brands through quality products.

We believe that key to our continued success in Refining and Marketing is holding a portfolio of quality, integrated, efficient positions and accessing available market growth in emerging markets. We intend to do this through holding positions in advantaged integrated FVCs where we will invest to strengthen our established positions.

We also intend to retain and grow our IBs.

In 2007, we identified that the segment s financial performance lagged that of our competitors, based on our analysis of our position compared with our supermajor peers, and we launched a programme to restore our financial performance. Our objective was to restore our performance over a period of three to four years by focusing on achieving safe, reliable and compliant operations, restoring missing revenues and delivering sustainable competitive returns and cash flows.

We believe our overall performance has now returned to being competitive with our supermajor peers, but that there is significant potential for further performance improvements. In the future, we intend to build on this by focusing on further improvements in operations, asset quality and overall efficiency, in order to be a leading player in each of the markets in which we choose to participate.

Our performance

Our 2009 performance has benefited from the fundamental improvements we have been making across the business, including the measures we have taken to restore the availability of our refining system, reduce costs and simplify the organization. The replacement cost profit before interest and tax was $0.7 billion for 2009, compared with $4.2 billion in 2008. The result was heavily impacted by non-operating items, which included a significant level of restructuring charges and a $1.6 billion one-off charge to write off all the segment s goodwill in the US West Coast FVC relating to our 2000 ARCO acquisition. This resulted from our annual review of goodwill as required under IFRS and reflects the prevailing weak refining environment that, together with a review of future margin expectations in the FVC, has led to a reduction in the expected future cash flows. The decrease in profit was also driven by the very significantly weaker environment, where refining margins fell by almost 40%. This was partly offset by significantly stronger operational performance in the fuels value chains, with 93.6% Solomon refining availability, lower costs and improved performance in the international businesses. Our financial results are discussed in more detail on pages 52-53.

Safety, both process and personal, remains our top priority. During 2009, we continued the migration to the BP operating management system (OMS) with a continuing focus on process safety. The OMS is described in further detail in Safety (*see page 42*). At the end of 2009, all our operated refineries and petrochemicals plants were using the OMS. Within our US refineries, we continued to implement the recommendations of the BP US Refineries Independent Safety Review Panel and regulatory bodies (*further information can be found in Safety on page 42 and in Legal proceedings on page 95*). The focus on operational integrity continues to yield positive results across the segment. Since 2005, when we started identifying incidents by type, we have reduced the overall number of major incidents by 90%. None of the major incidents reported in 2009 was integrity-management related. We have also reduced the number of reported oil spills and the recordable injury frequency in our workforce to the lowest level for 10 years. In 2009, there were no reported workforce fatalities associated with our refining and marketing operations.

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In 2009, despite the impact on our overall results of the weak refining environment, our focus on operations delivered significant performance improvements, both financial and operational. Solomon availability for the year was around five percentage points higher than in 2008. Average throughputs were up by over 130,000b/d compared with 2008, an increase of more than 6%. In addition, 2009 has seen further improvements at our Texas City refinery. Production has ramped up steadily during the year and availability has increased each quarter. During April 2009, the site s Solomon availability exceeded 90% for the first time in four years.

Our financial performance also benefited from lower non-feedstock costs. In 2009, our total costs were over 15%[a] lower than in 2008. In addition we reduced our headcount, excluding retail store staff, by over 2,600 (*see Financial statements Note 39 on page 172*).

[a] Based on Refining and Marketing s share of production and manufacturing expenses plus distribution and administration expenses.

Key statistics

			$ million
	2009	2008	2007
Sales and other operating revenues[a]	**213,050**	320,039	250,221
Replacement cost profit before interest and tax[b]	**743**	4,176	2,621
Total assets	**82,224**	75,329	95,311
Capital expenditure and acquisitions	**4,114**	6,634	5,495
			thousand barrels per day
Total refinery throughputs	**2,287**	2,155	2,127
			thousand tonnes
Total chemicals production[c]	**12,391**	12,518	14,028
			$ per barrel
Global indicator refining margin[d]	**4.00**	6.50	9.94
Refining availability[e]	**93.6%**	88.8%	82.9%

[a] Includes sales between businesses.

[b] Includes profit after interest and tax of equity-accounted entities.

[c] A minor amendment has been made to comparative periods.

[d] The global indicator refining margin (GIM) is the average of regional industry indicator margins weighted 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 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.

[e] Refining availability represents Solomon Associates operational availability, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory maintenance downtime.

Sales and other operating revenues are analysed in more detail below.

			$ million
	2009	2008	2007
Sale of crude oil through spot and term contracts	**35,625**	54,901	43,004
Marketing, spot and term sales of refined products	**166,088**	248,561	194,979
Other sales and operating revenues	**11,337**	16,577	12,238
	213,050	320,039	250,221

Oil sales volumes

			thousand barrels per day
Refined products	**2009**	2008	2007
US	**1,426**	1,460	1,533
Europe	**1,504**	1,566	1,633
Rest of World	**630**	685	640
Total marketing sales[a]	**3,560**	3,711	3,806
Trading/supply sales[b]	**2,327**	1,987	1,818
Total refined product sales	**5,887**	5,698	5,624
Crude oil	**1,824**	1,689	1,885
Total oil sales	**7,711**	7,387	7,509

[a] 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).

[b] 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	**2009**	2008	2007
Aviation fuel	**495**	501	490
Gasolines	**1,444**	1,500	1,572

Middle distillates	**1,012**	1,055	1,119
Fuel oil	**418**	460	429
Other products	**191**	195	196
Total marketing sales	**3,560**	3,711	3,806

Marketing volumes were 3,560mb/d, slightly lower than last year, reflecting the impact of slowing global economies on demand for fuel and the volume effects of our business simplification.

Outlook

For 2010, although demand has stabilized, the overall economic environment is expected to continue to be very challenging with continuing pressure on the demand for our products and on margins.

In response, our priorities in 2010 remain consistent with those in 2009 and we intend to build on the momentum we have established around improving financial performance and operations. We will continue to focus on delivering safe, reliable and compliant operations, improving the performance of our integrated FVCs, in particular in the US, and driving further cost efficiencies across all our businesses. We intend to maintain investment at 2009 levels, focused on key safety and operational integrity priorities, maintaining our quality manufacturing and marketing portfolio, strengthening our US Mid-West FVC business through the Whiting refinery modernization project and continuing to grow our advantaged petrochemicals business in China.

Business review

Fuels value chains

We have six regionally organized integrated FVCs, covering the West Coast and Mid-West regions of the US, the Rhine region, Southern Africa, Australasia (ANZ) and Iberia. Each of these is a material business, optimizing activities across the supply chain from crude delivery to the refineries; manufacture of high-quality fuels to meet market demand; pipeline and terminal infrastructure and marketing and sales to our customers. The Texas City refinery is not part of an integrated FVC but is operated as a standalone, predominantly merchant, refining business that also supports our marketing operations on the east and Gulf coasts of the US.

We also have a number of regionally focused fuels marketing businesses that are not integrated into a refinery, covering the UK, France and Turkey.

In 2009, the FVCs accounted for roughly three-quarters of the operating capital employed[a] in Refining and Marketing and generated just under half of the profit, after adjusting for non-operating items and fair value accounting effects. Without these adjustments, the result for the FVCs was a significant loss in 2009, with the most significant factor being the impairment charge to write off all the segment s goodwill in the West Coast fuels value chain.

Significant events in the FVCs in 2009 were as follows:

In February 2009, a new 20,000b/d coker was commissioned at our Castellón refinery in Spain. This was the culmination of a four-year project to convert the Castellón refinery to one capable of upgrading all fuel oil to higher value products. This will allow the refinery to produce about 50% more diesel than it did before, for sale to the local Spanish market and will also improve the ability of the refinery to process higher-margin heavy crude oils.

The Whiting refinery modernization project is more than one year into construction. The engineering design is now almost complete and many of the large foundations are in place. For further details on permit issues relating to our planned upgrades see Environment on page 45.

In July 2009, BP announced that it would not be progressing with the project with Irving Oil to build a refinery at Eider Rock in Saint John, New Brunswick, Canada as a result of global economic and industry conditions.

In December 2009, BP completed the sale of our ground fuels marketing business in Greece, to Hellenic Petroleum for $0.5 billion. The sale included a BP brand licence agreement for at least three years.

In November 2007, BP announced that it would sell all of its company-owned and company-operated convenience sites in the US. The sites will be supplied with BP or ARCO branded fuels under a 20-year contract and will continue to market BP-branded fuels in the eastern US and ARCO-branded fuels in the western US. By the end of 2009, we were no longer operating any of these sites and had completed the sale of all but around 30.

In the fourth quarter of 2009, we announced that we would explore options to divest a number of non-strategic pipelines and terminals in the US Mid-West, Gulf Coast and West Coast during 2010 and 2011.

In February 2010, we announced that we had received an offer from Delek Europe B.V. for the retail fuels and convenience business and selected fuels terminals in France. As a result, BP has agreed a period of exclusivity with Delek Europe B.V. to negotiate the terms for the sale and to allow consultation with the relevant works councils. Any transaction will be subject to regulatory approval. Any transaction is expected to include a BP brand licence agreement.

[a] Operating capital employed is total assets (excluding goodwill) less total liabilities, excluding finance debt and current and deferred taxation.

Refineries

BP 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 synergies with other parts of the group s business. Our refining focus is to maintain and improve our competitive position through sustainable, safe, reliable, compliant and efficient operations of the refining system and disciplined investment for integrity management, to achieve competitively advantaged configuration and 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.

Business review

The following table summarizes the BP group s interests in refineries and average daily crude distillation capacities at 31 December 2009. In July 2009, BP disposed of its 17.1% interest in Kenya Petroleum Refineries Ltd to Essar Energy Overseas Ltd.

					thousand barrels per day
				Crude distillation capacities[a]	
	Refinery	Fuels value chain	Group interest[b] %	Total	BP share
Europe					
Germany	Bayernoil	Rhine	22.5%	215	48
	Gelsenkirchen[c]	Rhine	50.0%	266	133
	Karlsruhe	Rhine	12.0%	323	39
	Lingen[c]	Rhine	100.0%	93	93
	Schwedt	Rhine	18.8%	226	42
Netherlands	Rotterdam[c]	Rhine	100.0%	386	386
Spain	Castellón[c]	Iberia	100.0%	110	110
Total Europe				1,619	851
US					
California	Carson[c]	US West Coast	100.0%	265	265
Washington	Cherry Point[c]	US West Coast	100.0%	234	234
Indiana	Whiting[c]	US Mid-West	100.0%	405	405
Ohio	Toledo[c]	US Mid-West	50.0%	160	80
Texas	Texas City[c]		100.0%	475	475
Total US				1,539	1,459
Rest of World					
Australia	Bulwer[c]	ANZ	100.0%	102	102
	Kwinana[c]	ANZ	100.0%	137	137
New Zealand	Whangerei	ANZ	23.7%	112	27
South Africa	Durban	Southern Africa	50.0%	180	90
Total Rest of World				531	356
Total				3,689	2,666

[a]Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.

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

[c]Indicates refineries operated by BP.
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]	**2009**	2008	2007
US	**1,238**	1,121	1,064
Europe	**755**	739	758
Rest of World	**294**	295	305
Total	**2,287**	2,155	2,127
Refinery capacity utilization			
Crude distillation capacity at 31 December[b]	**2,666**	2,678	2,769
Refinery utilization[c]	**86%**	81%	77%
US	**85%**	77%	69%
Europe	**89%**	87%	88%
Rest of World	**83%**	80%	83%

[a]Refinery throughputs reflect crude oil and other feedstock volumes.

[b]Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.

[c]Refinery utilization is annual throughput divided by crude distillation capacity, expressed as a percentage. The measure has been redefined in 2009 to be more consistent with industry standards. Prior periods have been restated.

Business review

Refining throughputs in 2009 increased by 6% relative to 2008, driven principally by improved operational performance in the US. Higher US throughputs were largely attributable to the recovery at the Texas City refinery, partially offset by the reduced equity interest in the Toledo refinery stemming from the Husky joint venture.

Supply and trading

The group has a long-established integrated supply and trading function responsible for delivering value across the overall crude and oil products supply chain. This structure enables the optimization of BP s FVCs to maintain a single interface with the oil trading markets and to operate with a single set of trading compliance processes, systems and controls. The business is organized along global commodity lines and with trading offices in Europe, the US and Asia, the function is able to maintain a presence in the regionally connected global markets. The supply and trading function has supported the Refining and Marketing segment through a period of higher volatility of crude and oil product prices and increased credit risk following the global financial crisis.

The function seeks to identify the best markets and prices for our crude oil, source optimal feedstocks for our refineries and provide competitive supply for our marketing businesses. In addition, where refinery production is surplus to marketing requirements or can be sourced more competitively, it is sold into the market. Wherever possible, the group will look to optimize value across the supply chain. For example, BP will often sell its own crude production into the market and purchase alternative crude for its refineries where this will provide incremental margin.

Along with the supply activity described above, the function seeks to create incremental trading opportunities. It enters into the full range of exchange-traded commodity derivatives, over-the-counter (OTC) contracts and spot and term contracts that are described in detail below. In order to facilitate the generation of trading margin from arbitrage, blending and storage opportunities, it also both owns and contracts for storage and transport capacity. The group has developed a risk governance framework to manage and oversee the financial risks associated with this trading activity, which is described in the Financial statements Note 24 on pages 142-147.

The range of transactions that the group enters into is described below.

Exchange-traded commodity derivatives

These contracts are typically in the form of futures and options traded on a recognized exchange, such as Nymex, SGX, ICE and Chicago Board of Trade. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate and the main product grades, such as gasoline and gasoil. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant exchange. These contracts are used for the trading and risk management of both crude oil and refined products. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

OTC contracts

These contracts are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties; others may be cleared by a central clearing counterparty. These contracts can be used both as part of trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in sales and other operating revenues for accounting purposes.

The main grades of crude oil bought and sold forward using standard contracts are West Texas Intermediate and a standard North Sea crude blend (Brent, Forties and Osberg or BFO). Although the contracts specify physical delivery terms for each crude blend, a significant volume are not settled physically. The contracts typically contain standard delivery, pricing and settlement terms. Additionally, the BFO contract specifies a standard volume and tolerance given that the physically settled transactions are delivered by cargo. Swaps are often contractual obligations to exchange cash flows between two parties: a typical swap transaction usually references a floating price and a fixed price with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell crude or oil products at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry, typically through netting agreements, to limit credit exposure and support liquidity.

Spot and term contracts

Spot contracts are contracts to purchase or sell crude and oil products at the market price prevailing on or around the delivery date when title to the inventory is taken. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. These transactions result in physical delivery with operational and price risk. Spot and term contracts relate typically to purchases of crude for a refinery, purchases of products for marketing, sales of the group s oil production and sales of the group s oil products. For accounting purposes, spot and term sales are included in sales and other operating revenues, when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.

Fuels marketing and logistics

Our fuels strategy focuses on optimizing the integrated value of each FVC that is responsible for the delivery of ground fuels 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 (which includes pipelines, storage terminals and road or rail tankers), 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 primarily focused on the ground fuels sector.

The ground fuels business supplies fuel and related convenience services 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 transport and industrial sectors.

Our retail network is largely concentrated in Europe and the US but also has established operations in Australasia, southern and eastern Africa. We are developing networks in China in two separate joint ventures, one with Petrochina and the other with China Petroleum and Chemical Corporation (Sinopec).

	Number of retail sites operated under a BP brand		
Retail sites[a b]	**2009**	2008	2007
US	**11,500**	11,700	12,200
Europe	**8,600**	8,600	8,600
Rest of World	**2,300**	2,300	2,500
Total	**22,400**	22,600	23,300

[a] The number of retail sites includes sites not operated by BP but instead operated by dealers, jobbers, franchisees or brand licensees that operate under a BP brand. These may move to or from the BP brand as their fuel supply or brand licence agreements expire and are renegotiated in the normal course of business.

[b] Excludes our interest in equity-accounted entities which are dual-branded.

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Business review

At 31 December 2009, BP s worldwide network consisted of some 22,400 sites branded BP, Amoco, ARCO and Aral, around the same as in the previous year. We continue to improve the efficiency of our retail network and increase the consistency of our site offer through a process of regular review. In 2009, we sold over 600 company-owned sites to dealers, jobbers and franchisees who continue to operate these sites under the BP brand. In addition we sold around 1,200 sites in Greece to Hellenic Petroleum, which will continue to be operated under the BP brand through a brand licensing agreement. We also divested around 100 company-owned sites to third parties.

Our retail convenience operations offer consumers a range of food, drink and other consumables and services on the fuel forecourt in a convenient and innovative manner. The convenience offer includes brands such as *ampm*, Wild Bean Café and Petit Bistro.

During 2009, we continued the implementation of our *ampm* convenience retail franchise model in the US. We expect this model to provide a reliable, long-term sales outlet for transport fuels from our refinery systems, together with reduced costs and lower levels of capital investment. Overall in the US, by the end of 2009 there were 11,500 branded retail sites of which 1,200 were branded *ampm*, compared with 11,700 and 1,100 respectively at the beginning of 2009.

In Europe, we are one of the largest forecourt convenience retailers, with about 2,500 convenience retail sites in 10 countries. We are growing our food-on-the-go and fresh grocery services through BP-owned brands and partnerships with leading retailers such as Marks & Spencer. In addition, at the end of 2009, we had approximately 500 sites outside Europe and the US in countries such as Australia, New Zealand and South Africa.

International businesses

Our IBs provide quality products and offers to customers in more than 80 countries worldwide with a significant focus on Europe, North America and Asia. Our products include aviation fuels, lubricants that meet the needs of various industries and consumers, LPG, and a range of petrochemicals that are sold for use in the manufacture of other products such as fabrics, fibres and various plastics. We believe each of these IBs is competitively advantaged in the markets in which we have chosen to participate. Such advantage is derived from several factors, including location, proximity of manufacturing assets to markets, physical asset quality, operational efficiency, technology advantage and the strength of our brands. Each business has a clear strategy focused on investing in its key assets and market positions in order to deliver value to its customers and outperform its competitors.

In 2009, the IBs accounted for just under a quarter of the segment s operating capital employed[a] and just over half the profit, after adjusting for non-operating items and fair value accounting effects. Without these adjustments, the profit for the IBs more than offset the loss for the FVCs.

Significant events in the international businesses in 2009 were:

Our expanded purified terephthalic acid (PTA) facility in Geel, Belgium was successfully commissioned in the first quarter of 2009. The expansion, which has a design capacity of 350 thousand tonnes per annum (ktepa), has improved operating costs and by the end of 2009 had already increased the site s PTA capacity by 255ktepa.

SECCO completed its first major turnaround in the third quarter of 2009 and at the same time expanded production capacity, creating China s largest ethylene cracker capable of producing 1.3mtpa of ethylene per year, an increase of 25%.

[a] Operating capital employed is total assets (excluding goodwill) less total liabilities, excluding finance debt and current and deferred taxation.

Construction of the new 500ktepa acetic acid plant in Jiangsu province, China by BP YPC Acetyls Company (Nanjing) Limited (BYACO) was completed. This is a BP joint venture with Yangzi Petrochemical Co. Ltd (a subsidiary of Sinopec). Commercial production is expected to begin in the second quarter of 2010.

BP and Sinopec continued to progress the project to add a new acetic acid plant at their Yangtze River Acetyls Co. (YARACO) joint venture site in Chongqing, China. This world-scale (650ktepa) acetic acid plant will use BP s leading Cativa technology. The expected plant start-up date is under review due to current market conditions. When complete, total production at the YARACO site is expected to be in excess of one million tonnes per annum, making this one of the largest acetic acid production locations in the world.

Lubricants

We manufacture and market lubricants and related products and services to the automotive, industrial, marine and energy markets across the world. Following a decision to simplify and focus our channels of trade, we now sell products direct to our customers in around 46 countries and use approved local distributors for the remaining locations. Customer focus, distinctive brands, superior technology and relationships remain the cornerstones of our long-term strategy.

BP markets primarily through its major brands of Castrol and BP, and also the Aral brand in some specific markets. Castrol is recognized as one of the most powerful lubricants brands worldwide and we believe it provides us with a significant competitive advantage. In the automotive lubricants sector, we supply lubricants and other related products and services to intermediate customers such as retailers and workshops. These, in turn, serve end-consumers such as car, truck and motorcycle owners in the mature markets of Western Europe and North America as well as the markets of Russia, China, India, the Middle East, South America and Africa, which we believe have the potential for significant long-term growth. In 2009, more than 30% of pre-tax operating income was generated from emerging markets.

BP marine lubricants is one of the largest global suppliers of lubricants to the marine industry. We supply many types of vessels from bulkers to container ships to dredgers and cruise ships, with global presence in over 850 ports. BP s industrial lubricants business is a leading supplier to those sectors of the market involved in the manufacture of automobiles, trucks, machinery components and steel. BP is also a leading supplier of lubricants for the offshore oil and aviation industries.

Petrochemicals

Our petrochemicals operations comprise the global Aromatics & Acetyls businesses (A&A) and the Olefins & Derivatives (O&D) businesses, predominantly in Asia. New investments are targeted principally in the higher-growth Asian markets.

In A&A we manufacture and market three main product lines: purified terephthalic acid (PTA), paraxylene (PX) and acetic acid. Our strategy is to leverage our industry-leading technology in selected markets, to grow the business and to deliver industry-leading returns. PTA is a raw material used in the manufacture of polyesters used in fibres, textiles and film, and polyethylene terephthalate (PET) bottles. Acetic acid is a versatile intermediate chemical used in a variety of products such as paints, adhesives and solvents, as well as its use in the production of PTA. We have a strong global market share in the PTA and acetic acid markets with a major manufacturing presence in Asia, particularly China. PX is a feedstock for PTA production. In addition to these three main products, we produce a number of other speciality petrochemicals products. We have a total of 14 manufacturing sites operating in the UK, the US, Belgium, China, Indonesia, Korea, Malaysia and Taiwan, including our joint ventures.

In O&D, we crack naptha and ethane as feedstocks to produce ethylene and other products and derivatives, within equity-accounted entities.

Business review

Our O&D business has operations in both China and Malaysia. In China, our SECCO joint venture between BP, Sinopec and its subsidiary, Shanghai Petrochemical Company, is the largest olefins cracker in China. SECCO is BP s single largest investment in China. This naphtha cracker produces ethylene and propylene plus derivatives acrylonitrile, polyethylene, polypropylene, styrene, polystyrene, butadiene and other products. In Malaysia, BP participates in two joint ventures: Ethylene Malaysia Sdn. Bhd. (EMSB), which produces ethylene from gas feedstock in a joint venture between BP, Petronas and Idemitsu; while Polyethylene Malaysia Sdn. Bhd. (PEMSB) produces polyethylene in a joint venture between BP and Petronas. BP also owns one other naphtha cracker site outside of Asia, which is integrated with our Gelsenkirchen refinery in Germany.

The following table shows BP s petrochemicals production capacity at 31 December 2009. This production capacity is based on the original design capacity of the plants plus expansions.

BP share of petrochemicals production capacity[a b]

						thousand tonnes per year
Geographic area	PTA	PX	Acetic acid	Other	O&D	Total
US	2,385	2,373	583	151		5,492
Europe	1,330	624	532	158	1,629	4,273
Rest of World	3,704		1,035	108	3,217	8,064
	7,419	2,997	2,150	417	4,846	17,829

[a] Petrochemicals capacity is the maximum proven sustainable daily rate (msdr) multiplied by the number of days in the respective period, where msdr is the highest average daily rate ever achieved over a sustained period.

[b] Includes BP share of equity-accounted entities.

Global fuels

The supply of aviation fuels and LPG is run globally in the global fuels SPU.

Air BP is one of the world s largest and best known aviation fuels suppliers, serving many of the major commercial airlines as well as the general aviation and military sectors. During 2009, which was another tough year for the aviation industry, we continued to simplify our geographical footprint by exiting non-core countries and we now supply customers in 64 countries. This has allowed us to reduce working capital and improve returns on operating capital employed.

We have annual marketing sales in excess of 25 billion litres. Air BP s strategic aim is to grow its position in the core locations of Europe, the US, Australasia and the Middle East, while focusing its portfolio towards airports that offer long-term competitive advantage.

The LPG business sells bulk, bottled, automotive and wholesale LPG products to a wide range of customers in 12 countries. During the past few years, our LPG business has consolidated its position and introduced new consumer offers in established markets, developed opportunities in growth markets and pursued new demand such as the German Autogas market. In 2009, we have divested non-core operations and focused our asset base around sustainable marketing operations. Annual sales are in excess of 2 million tonnes per annum.

Other businesses and corporate

Other businesses and corporate comprises the Alternative Energy business, Shipping, the group s aluminium asset, Treasury (which includes interest income on the group s cash and cash equivalents), and corporate activities worldwide.

The financial results of Other businesses and corporate are discussed on page 53.

Key statistics

			$ million
	2009	2008	2007
Sales and other operating revenues[a]	**2,843**	4,634	3,698
Replacement cost profit (loss) before interest and tax[b]	**(2,322)**	(1,223)	(1,209)
Total assets	**17,954**	19,079	20,595
Capital expenditure and acquisitions	**1,299**	1,839	939

[a] Includes sales between businesses.

[b] Includes profit after interest and tax of equity-accounted entities.

Alternative Energy

Alternative Energy comprises BP s low-carbon businesses and future growth options outside oil and gas. Alternative Energy is focused on four key businesses, which we believe have the potential to be a material source of low-carbon energy and are aligned with BP s core capabilities. These are biofuels, wind, solar, and hydrogen power and carbon capture and storage (CCS).

Our market

It is now well accepted that a more diverse mix of energy will be required to meet future demand. The International Energy Association (IEA)[a] estimates that world energy demand could be 40% higher than at present by 2030, driven largely by China and India. The IEA also projects that higher fossil-fuel prices, as well as increasing concerns over energy security and climate change, could boost the share of wind and solar electricity generation from 1% in 2007 to 6% in 2030, and the biofuels share of transport fuels from 1% in 2007 to 4% in 2030[b].

Our performance

Alternative Energy made good progress in 2009. Our wind business has added 279MW of capacity including the construction of two wind farms in the US Fowler Ridge II in Indiana and Titan I in South Dakota taking the total capacity in commercial operation to 711MW (1,237MW gross) at the end of 2009. In our solar business, we completed the restructuring of our manufacturing facilities and increased unit sales 25% over 2008. Our biofuels business is investing in advanced technologies. We have our first joint-venture ethanol refinery in Brazil and another joint-venture facility is under construction in the UK.

Since 2005, we have invested more than $4 billion[c] in Alternative Energy, in line with our commitment to invest $8 billion by 2015.

[a] Adapted from *World Energy Outlook 2009.* ©OECD/IEA 2009, page 73.

[b] *World Energy Outlook 2009.* ©OECD/IEA 2009, pages 622-623: Reference Scenario, World .

[c] The majority of costs have been capitalized, some were expensed under IFRS.

	2009	2008	2007
Wind net rated capacity at year-end (megawatts[a])	**711**	432	172
Solar module sales (megawatts[b])	**203**	162	115

[a] Net wind capacity is the sum of the rated capacities of the assets/turbines that have entered into commercial operation, including BP s share of equity-accounted entities. The equivalent capacities on a gross-JV basis (which

includes 100% of the capacity of equity-accounted entities where BP has partial ownership) were 1,237MW in 2009, 785MW in 2008 and 373MW in 2007. This includes 32MW of capacity in the Netherlands that is managed by our Refining and Marketing segment.

[b] Solar sales are the total sales of solar modules to third-party customers, expressed in MW. Previously we reported the theoretical cell production capacity of our in-house solar manufacturing facilities. Reporting sales volumes operating data brings us into line with the broader solar industry.

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Business review

Biofuels

BP has a key role to play in enabling the transport sector to respond to the dual challenges of energy security and climate change. We have embarked on a focused programme of biofuels development based around the most efficient transformation of sustainable and low-cost sugars into a range of fuel molecules. BP continues to invest throughout the entire biofuels value chain from sustainable feedstocks that minimize pressure on food supplies through to the development of the advantaged fuel molecule biobutanol. BP has production facilities operating, or in the planning and construction phases, in the US, Brazil and the UK.

In 2009, we announced a $45-million investment in a joint venture with Verenium which plans to construct a facility to produce lignocellulosic bioethanol in Florida, US. This investment builds on the $90-million investment made by BP in 2008 to further develop existing Verenium technical work and develop a demonstration plant at commercial scale. In August, BP also announced a $10-million multi-year agreement with Martek Biosciences Corporation to establish proof of concept for large-scale microbial biodiesel production through the fermentation of sugars.

The blending and distribution of biofuels continues to be carried out by our Refining and Marketing segment, in line with regulation. BP is one of the largest blenders and marketers of biofuels in the world.

Wind

In wind power, BP has focused its portfolio in the US, where we believe the most attractive opportunities exist and where we have developed one of the leading wind portfolios.

During 2009, we announced the completion of phase I of the 100MW Flat Ridge Wind Farm in Barber County, Kansas. BP and Westar Energy, Inc. each own 50% of phase 1 of the wind farm. BP sells its share of the output to Westar. In addition, commercial operations commenced at the Fowler Ridge Wind Farm in Benton County, Indiana, the largest wind farm in the US Midwest at 600MW, where BP and Dominion are equal partners in 300MW. BP and Sempra Generation are equal partners in 200MW, and 100MW is wholly-owned by BP. Full commercial operation also began at our wholly-owned 25MW Titan I Wind Farm in South Dakota.

As a result, BP has increased its net wind generation capacity to 711MW during 2009, an increase of 65% over the prior year. This net increase in capacity includes the disposal of 78MW of our wind interests in India as part of our focus on US wind.

Solar

2009 was quite challenging in the solar market due to weak demand in the first half year and a significant decrease in module sales prices of about 40%. However, BP Solar was successful in increasing unit sales by 41MW to 203MW, an increase of 25% over 2008.

BP Solar s organization, with over 1,700 employees worldwide, is headquartered in San Francisco, California, in the US. BP Solar is structured to serve the residential, commercial, and utility markets with sales and marketing offices in major markets around the world. Our manufacturing facilities are located in Frederick, Maryland, US; and joint venture manufacturing is located in Xi an, China and Bangalore, India[a]

During 2009, BP Solar continued to restructure manufacturing to reduce costs and, as part of this programme, module assembly was phased out in Maryland and our cell manufacture and module assembly facilities in Madrid, Spain, were closed. Wafer and cell manufacturing facilities in Maryland and joint venture manufacturing sites in China and India continue to supply BP Solar.

[a]Our Indian manufacturing operations are accounted for as a consolidated subsidiary.

Hydrogen power and CCS

BP has played a leading role in the CCS industry for more than 10 years, and today focuses on both full-scale projects and a continuing programme of research and technology development. The Hydrogen Energy International Limited joint venture, which was formed to develop hydrogen power projects in 2007, is now wholly owned by BP following an agreement with Rio Tinto to sell its 50% share.

The two companies are continuing to develop the Hydrogen Energy California 250MW power project with CCS through the Hydrogen Energy International LLC joint venture, which secured $308 million of Department of Energy (DoE) funding during 2009. The funding award was made to California as part of the American Recovery Reinvestment Act of 2009 and is part of the third round of the DoE s Clean Coal Power Initiative.

Separately, the 400MW Hydrogen Power Abu Dhabi project with CCS reached an important milestone, with the Abu Dhabi environmental regulator s approval of the environment and social impact assessment. The project is a joint venture between BP (40%) and Masdar (60%).

Shipping

We transport our products across oceans, around coastlines and along waterways, using a combination of BP-operated, time-chartered and spot-chartered vessels. All vessels conducting BP activities are subject to our health, safety, security and environmental requirements. The primary purpose of our shipping and chartering activities is the transportation of our hydrocarbon products. In addition, we may use surplus capacity to transport third-party products.

International fleet

The size of our managed international fleet has not changed since 2008. At the end of 2009, we had 54 international vessels (37 medium-size crude and product carriers, four very large crude carriers, one North Sea shuttle tanker, eight LNG carriers and four LPG carriers). All these ships are double-hulled. Of the eight LNG carriers, BP manages one on behalf of a joint venture in which it is a participant and operates seven LNG carriers.

Regional and specialist vessels

In Alaska, we retain a fleet of four double-hulled vessels. Outside the US, we had 14 specialist vessels (two double-hulled lubricants oil barges and 12 offshore support vessels).

Time-charter vessels

BP has 104 hydrocarbon-carrying vessels above 600 deadweight tonnes on time-charter, of which 102 are double-hulled. All these vessels participate in BP s Time Charter Assurance Programme.

Spot-charter vessels

BP spot-charters vessels, typically for single voyages. These vessels are always vetted for safety assurance prior to use.

Other vessels

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

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Maritime security issues

At a strategic level, BP avoids known areas of pirate attack or armed robbery; where this is not possible for trading reasons and we consider it safe to do so, we will continue to trade vessels through these areas, subject to the adoption of heightened security measures.

2009 has seen continuing pirate activity in the Gulf of Aden, extending into the Indian Ocean (from the east coast of Somalia to beyond the Seychelles) and a significant increase in the number of international shipping incidents. The number of vessels actually hijacked has remained roughly the same as 2008, as a result of heightened awareness to the threat, and protective measures adopted by transiting ships.

At present, we follow available military and government agency advice and are participating in protective group transits through the Gulf of Aden Maritime Security Patrol Area transit corridor. BP supports the protective measures recommended in the international shipping industry guide *Best Management Practices to Deter Piracy in the Gulf of Aden*[a].

Aluminium

Our aluminium business is a non-integrated producer and marketer of rolled aluminium products, headquartered in Louisville, Kentucky, US. Production facilities are located in Logan County, Kentucky, and are jointly owned with Novelis. The primary activity of our aluminium business is the supply of aluminium coil to the beverage can business, which it manufactures primarily from recycled aluminium.

Treasury

Treasury manages the financing of the group centrally, ensuring liquidity sufficient to meet group requirements and manages key financial risks including interest rate, foreign exchange, pension and financial institution credit risk. From locations in the UK, the US and the Asia Pacific region, Treasury provides the interface between BP and the international financial markets and supports the financing of BP s projects around the world. Treasury trades foreign exchange and interest rate products in the financial markets, hedging group exposures and generating incremental value through optimizing and managing flows. Trading activities are underpinned by the compliance, control, and risk management infrastructure common to all BP trading activities.

Insurance

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

[a]Jointly published and supported by Industry bodies, including OCIMF.

Research and technology

Research and technology (R&T) has a critical role to play in addressing the world s energy challenges, from fundamental research through to wide-scale deployment. BP s model is one of selective technology leadership, where we have chosen 20 major technology programmes 10 in Exploration and Production, seven in Refining and Marketing and three focused on lower-carbon value chains.

Inside the business segments, the full breadth of these activities is carried out in service of competitive business performance and new business development, through research and development (R&D) or acquisition of new technologies. The central R&T group provides leadership and assurance for scientific and technological activities across BP with a focus on having the right capability in critical areas, overseeing the quality of BP s major technology programmes, and illuminating the potential of emerging science. External assurance is achieved through the Technology Advisory Council, which advises the board and executive management on the state of research and technology within BP. The Council comprises typically eight to 10 world-leading and eminent industrialists and academics.

R&D is carried out using a balance of internal and external resources. Involving third parties in the various steps of technology development and application enables a wider range of ideas and technologies to be considered and implemented, improving the impact of research and development activities and the leverage of our spend.

Across the group, expenditure on R&D for 2009 was $587 million, compared with $595 million in 2008 and $566 million in 2007. See Financial statements Note 11 on page 132. Despite the economic downturn of 2009, R&D spending remained roughly flat. In addition we increased our focus on value realization from the application of technology (including field trials), and capability development, which are not included in the headline R&D expenditure.

In our Exploration and Production segment, we selectively focus on 10 flagship technology programmes which have the greatest business impact. We consider that each has the potential to add more than one billion boe to reserves through their development and deployment in our assets worldwide. These technologies continue to contribute to exploration and production success in Alaska, Angola, Azerbaijan, Egypt, North Africa, the North Sea, Trinidad and the deepwater Gulf of Mexico. 2009 highlights from four of these flagships include:

Advanced seismic imaging BP s expertise leads the industry, with cutting-edge simultaneous sweeping techniques being successfully applied in onshore seismic surveys in Libya and Oman. Offshore, BP completed its largest ever 3D surveys in Libya s deepwater, carried out the most northerly 3D seismic programme ever conducted (in the Canadian Beaufort Sea), and deployed a wide azimuth towed streamer in Angola an acquisition configuration developed by BP to image areas of complex geology below salt. These imaging techniques significantly reduce time and costs needed to acquire seismic data over vast areas.

Enhanced oil recovery (EOR) technologies are pushing recovery factors to new limits. By increasing the overall recovery factor from our fields by 1%, we believe we can add 2 billion boe to our reserves. At the Endicott field in Alaska, BP completed a field trial of its LoSal™ EOR technology, which uses injection water with a much lower than usual salt content to flush out or displace extra oil from the reservoir. Following the success of this trial, the technology is now being actively considered for application in several new projects. BP has now performed 38 Bright Water treatments in Alaska, Argentina and Pakistan, which have delivered an increase of more than 9 million barrels to our recoverable volumes at a development cost of less than $6 per barrel.

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Field-of-the-Future™ (FotF) exploits digital technologies to improve performance and optimize production. For example, ISIS, a proprietary system designed by BP engineers, gathers subsurface information from wells in real time using field sensors that measure parameters such as pressures and temperatures. ISIS has now been deployed as a virtual flow meter and has improved production rates at Thunder Horse and other fields. BP has deployed FotF to 35 operations using a common platform, leading the industry in this area.

Inherently reliable facilities BP conducted a high reliability chemical injection skid field trial at Wytch Farm in the UK, as part of this flagship s objectives of improving corrosion inhibition, extending the life of BP s assets and ensuring safe, reliable and efficient operations.

In our Refining and Marketing segment, technology is delivering performance improvements across all businesses. For example:

Refining technology advances are enabling better understanding and processing of feedstocks of varying quality and optimization of our assets in real time, enhancing the flexibility and reliability of our refineries and improving margins. The reconfiguration at Whiting refinery to process heavier crudes is on track, incorporating technologically advanced coking operations. BP s Refinery-of-the-Future programme develops and deploys state-of-the-art measurement, monitoring and predictive technologies to improve refinery safety, integrity, availability and utilization, and to optimize feedstock selection and blending. For example, BP has completed large-scale field trials of wireless, online, sensors for remote corrosion monitoring, and deployment across our refineries is now under way.

BP s leading technologies in **fuels and lubricants** mean that it can keep ahead of increasingly stringent regulations, balancing greater fuel efficiency and performance and developing superior formulations across its entire product slate. In 2009, BP completed the launch of Castrol EDGE Sport, a range of highly advanced synthetic engine oils that outperform conventional, high mileage, part synthetic and benchmark synthetic motor oils. BP s strong relationship with Ford has contributed to important technological advances in fuel and lubricants products, including a joint UK Government-backed project to improve fuel efficiency, which has achieved reductions in friction and a significant overall reduction in fuel usage for next generation engines.

Our proprietary processing technologies and operational experience continue to reduce the manufacturing costs and environmental impact of our **petrochemicals** plants, helping to maintain competitive advantage in purified terephthalic acid (PTA) and acetic acid. Learning from successful project implementations in Asia, continuous improvement of our CATIVA® technology for manufacture of acetic acid maintains BP s world-class capital and conversion cost position.

In the field of **conversion technology**, our Fischer-Tropsch demonstration plant programme in Nikiski, Alaska, has been completed, proving the performance of BP s fixed-bed process. This technology is now ready for commercial deployment and available for third-party licensing. The process is particularly well suited for the chemical conversion of biomass-derived feedstocks to liquids.

BP s Alternative Energy portfolio covers a wide range of renewable and low-carbon energy technologies.

In 2009, our **biofuels** business extended its reach and capability through joint ventures with Dupont (to develop, produce and market next-generation biofuels from biobutanol), Verenium (two 50:50 JVs accelerating the development and commercialization of biofuels from lignocellulosic feedstocks), and Martek Biosciences (developing technology to convert sugars into diesel).

In our **solar** business, BP has joined forces with Interuniversity Microelectronics Centre (IMEC) and other partners to demonstrate high-efficiency, low-cost silicon Mono2™ solar cells. This new technology is producing cells ranging up to 18% efficiency, compared with multicrystalline cells that are typically around 15%-15.8%

efficiency. Mono2 cells are fabricated using BP Solar s proprietary casting technique to produce monocrystalline wafers. BP Solar has also developed and is in the process of commercializing a full portfolio of module technology. This uses advanced heat management and internal microcircuits to optimize energy production, safety, and ease of operation and maintenance.

Our **carbon capture and storage** projects in Abu Dhabi and California are making progress, with environmental regulator approval for the former and Department of Energy funding for the latter.

Collaboration plays an important role across the breadth of BP s research and development activities, but particularly in those areas that benefit from fundamental scientific research:

BP has 11 significant, **long-term research programmes** with major universities and research institutions around the world, exploring areas from energy bioscience and conversion technology to carbon mitigation and nanotechnology in solar power. In 2009, we established an EOR exploratory research programme with three European universities to improve our understanding, foster innovation and provide a springboard for new technologies.

At our **Energy Biosciences Institute** at Berkeley, we have located BP researchers at the institute to collaborate with the academic researchers. Several foundational research platforms have been established (including second-generation biofuel technologies and microbially-enhanced oil and gas recovery) and the first patents and inventions have started to emerge.

BP is an industry member of the UK s **EnergyTechnologies Institute** (ETI) a public/private partnership to accelerate low-carbon technology development. In 2009, the ETI commissioned over £50 million ($80 million) of work covering 10 projects across a wide range of technologies. The ETI has also developed a model of the UK energy system which projects out to 2050.

In 2009, BP launched the **Energy Sustainability Challenge**, a three-year study into how changes in availability of and demand for natural resources and ecosystem services will affect future energy supply and demand, the technologies that could enable more efficient use of natural resources, and the policies that will be necessary to bring these into effect.

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Corporate responsibility

Safety

Safety, people and performance are BP s top priorities. We constantly seek to improve our safety performance through the procedures, processes and training programmes that we implement in pursuit of our goal of no accidents, no harm to people and no damage to the environment .

In 2009, a third-party-operated helicopter carrying contractors from BP s Miller platform crashed in the North Sea resulting in the tragic loss of 16 lives. In addition, BP sustained two fatalities within our own operations, one, when a rig worker was lost overboard during drilling operations in Azerbaijan and a second, in a crush injury on a well pad in Alaska.

We deeply regret the loss of these lives.

Safety and operational performance

In 2009, BP s safety record continued to improve, as indicated by measures of personal safety including reported recordable injury frequency (RIF) and days away from work case frequency (DAFWC).

Our overall RIF of 0.34 was significantly lower than the rate of 0.43 in 2008 and 0.48 in 2007. Our DAFWCF was 0.069, an improvement on the level of 0.080 in 2008.

In 2009, eight work-related major incidents were reported, compared with 21 in 2008. Major incidents include incidents resulting in fatalities, significant property damage or significant environmental impacts. All fatalities and other major incidents and many that have the potential to become major incidents, are discussed by the group operations risk committee (GORC), chaired by the group chief executive. Our mandatory internal requirement to undertake incident investigations seeks to ensure that we learn as much as possible from each incident and take action to prevent re-occurrence.

There were 234 oil spills of one barrel or more reported in 2009, a significant reduction on the 335 spills that occurred in 2008. The reported volume of oil spilled in 2009 was approximately 1,191 million litres, a reduction of 65% compared with 2008.

This performance follows several years of intense focus on training and procedures across BP. BP s operating management system (OMS), which provides a single operating framework for all BP operations, is a key part of continuing to drive a rigorous approach to safe operations. 2009 marked an important year in the continuing implementation of OMS.

Safe, reliable and responsible operations

Having been introduced at eight operating sites in 2008, implementation of the OMS gathered pace in 2009. The system was up and running at 70 operations across the business by the end of the year, including all our operated refineries and petrochemicals plants. This represents around 80% of the operations for which OMS implementation is planned, with the remainder scheduled to be live by the end of 2010.

Taking a systematic approach is integral to improving safety and operating performance in every BP site. Our OMS covers all areas from process safety, to personal health, to environmental performance. By applying consistent principles and processes across the BP group s operations, the system provides for an integrated and consistent way of working. These principles and processes are designed to simplify the organization, improve productivity, enable consistent execution and focus BP on performance.

Capability development

Having built a safety and operations learning framework to enhance the capability of our staff to deliver safe, reliable, responsible and efficient operations, we defined target populations for these programmes more accurately in 2009.

More than 2,700 front-line operational leaders across our global operations have started one or more of the modules within the Operating Essentials programme which seeks to embed the BP way of operating as defined by OMS. Our Operations Academy (OA), a partnership with the Massachusetts Institute of Technology (MIT), is also now well established. Seven cadres of senior operations staff have already attended this academy and three of these have graduated: all are applying their learning and having a deep influence in the operations community. We also have an Executive Operations Programme which has continued to support the executive team and senior business leaders in the development of their unique operations capability requirements.

Process safety management

We continued to implement the 2007 recommendations made by the BP US Refineries Independent Safety Review Panel (Panel), which following the incident at Texas City in 2005, reviewed process safety management at our US refineries and our safety management culture.

In accordance with those recommendations, we appointed an Independent Expert for a five-year term to monitor their implementation. We again co-operated closely with the Independent Expert in 2009, providing him access to our sites, personnel and documentation and routinely supplying him with progress reports. In the Independent Expert s second annual report, published in 2009, he acknowledged BP s sustained focus on its safety and operations agenda and the priority given by executive management and the board to safe, reliable and responsible operations. The report identified areas for continued focus and highlighted the progress made in several areas, including the development of capability programmes, OMS implementation, safety and operations auditing, and the improvement of metrics to monitor process safety performance. During the course of 2009, we also provided regular progress updates to the Safety, Ethics and Environment Assurance Committee of the board.

See Legal proceedings on pages 95-96 in respect of ongoing Texas City refinery matters.

By the end of 2009 our safety and operations audit team had audited a total of 94 BP businesses, including all major operating sites, within a three-year period. The audits, which in 2009 included pilot audits for analysis against the requirements of the OMS, have provided a rigorous process for assessing our businesses against BP s relevant standards and requirements.

We also participated in industry-wide forums on process safety. We chaired the API/ANSI multi-stakeholder group developing a standard for public reporting of leading and lagging process safety indicators. Through this and other bodies, we shared our learning with other organizations within and outside the oil and gas industry.

Six-point plan

Our efforts on process safety included taking action to close out our six-point plan for process safety, which was launched in 2006 to address immediate priorities for improving process safety and minimizing risk at our operations worldwide. We have either completed the required actions or integrated the few continuing requirements within the OMS, for tracking to completion. We established a clear approach for future monitoring of these within the internal HSE & Operations Integrity Report. This report, which is the key source of management information relating to safety and operations in BP, is prepared quarterly for the GORC.

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Environment

Climate change

BP recognizes that climate change is a global concern representing a significant challenge for society, the energy industry, and BP.

We monitor and report on greenhouse gas (GHG) emissions[a], and we manage our GHG emissions through a focus on operational energy efficiency. Each year since 2002, we have estimated the reduction in our reported annual emissions due to efficiency projects and the running total of these estimated reductions is now 7.9 million tonnes (Mte), including 0.3Mte estimated for the last year.

However, last year s sustainable reductions have been more than offset by additional emissions from increased operational activity. As such, we are reporting 65.0Mte of GHG emissions for the year 2009, 3.6Mte higher than the 61.4Mte reported for 2008. Increased throughput from US refineries, the start-up of our Tangguh LNG project in Indonesia and deepwater production platforms in the Gulf of Mexico account for much of this increase.

We expect that additional regulation of GHG emissions in the future and international accords aimed at addressing climate change will have an increasing impact on our businesses, operating costs and strategic planning, but may also offer opportunities in the development of low-carbon technologies and businesses. See Regulation Greenhouse gas regulation on page 44.

To address this expectation, we factor a carbon cost into our investment appraisals and the engineering design of new projects. We do this by requiring projects to make realistic assumptions about the likely carbon price during the lifetime of the project. This is used as a basis for assessing the economic value of the investment, and for assessing options to optimize the way the project is engineered. This is our way of evaluating investments to ensure they are competitive not only in today s world but in a future where carbon has a more robust price.

Environmental management

During 2009, we began integrating our environmental management systems into our operating management system (OMS) and piloted an integrated approach to identify potential environmental and social impacts in new projects. These are intended to improve our consistency and effectiveness in identifying and mitigating the environmental and social impacts of our operations. Our major operating sites are all certified under the international environmental management system standard ISO 14001, with the exception of the Texas City petrochemicals plant which is seeking certification in 2010.

None of our new projects entered a protected area in 2009. Our protected areas classification includes the International Union for the Conservation of Nature (IUCN) I-IV, Ramsar and World Heritage designations.

We continue to strengthen our processes for managing compliance with environmental regulations in each of the countries in which we operate. In addition, each employee is required to comply with the health, safety and environmental requirements of the BP code of conduct. We expect our partners, suppliers and contractors to comply with legal requirements and operate consistently with the principles of our code of conduct.

Information on the environmental impact of our operations and our efforts to manage resources responsibly are discussed in our annual BP Sustainability Report which is available on our website at *www.bp.com/sustainability*.

[a] We report greenhouse gas (GHG) emissions, and emission reductions, on a CO_2-equivalent basis including CO_2 and methane. This represents all consolidated entities and BP s share of equity-accounted entities except TNK-BP.

Technology development

BP invests in, or jointly funds, research and development seeking opportunities to reduce our potential environmental impacts, for example, sound and marine life research, a range of water management projects and advanced drill cuttings treatment. BP also participates in public and private partnerships to develop new technologies. These include:

- the Energy Biosciences Institute (EBI) in the US, which conducts research into biofuel technologies, improved oil and gas recovery and carbon sequestration;

the Energy Technologies Institute (ETI) in the UK, which seeks to accelerate the development of energy technologies to reduce GHG emissions including offshore wind and for marine, tidal and wave energy; and

the Carbon Mitigation Initiative at Princeton University, to research the fundamental environmental, and technological issues in carbon management.

Regulation

BP operates in more than 80 countries and is subject to a wide variety of environmental regulations concerning our products, operations and activities. Current and proposed fuel and product specifications, emission controls and climate change programmes under a number of environmental laws may have a significant effect on the production, sale and profitability of many of our products.

There also are environmental laws that require us to remediate and restore areas damaged by the accidental or unauthorized release of hazardous materials or petroleum associated with our operations. These laws may apply to sites that BP currently owns or operates, sites that it previously owned or operated, or sites used for the disposal of its and other parties waste. Provisions for environmental restoration and remediation are made when a clean-up is probable and the amount of BP s legal obligation can be reliably estimated. The cost of future environmental remediation obligations is often inherently difficult to estimate. Uncertainties can include the extent of contamination, the appropriate corrective actions, technological feasibility and BP s share of liability. See Financial statements Note 34 on page 158 for the amounts provided in respect of environmental remediation and decommissioning.

A number of pending or anticipated governmental proceedings against BP and certain subsidiaries under environmental laws could result in monetary sanctions of $100,000 or more. We are also subject to environmental claims for personal injury and property damage alleging the release or exposure to hazardous substances. The costs associated with such future environmental remediation obligations, governmental proceedings and claims could be significant and may be material to the results of operations in the period in which they are recognized, but it is not expected that such costs will be material to the group s overall results of operations, our financial position or liquidity. However, we cannot accurately predict the effects of future developments on the group, such as stricter environmental laws or enforcement policies or future events at our facilities, and there can be no assurance that material liabilities and costs will not be incurred in the future. For a discussion of the group s environmental expenditure see page 56.

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Greenhouse gas regulation

Increasing concerns about climate change have led to a number of international, national and regional measures to limit greenhouse gas emissions; additional stricter measures can be expected in the future. Current measures and developments affecting our businesses include the following:

- The Kyoto Protocol currently commits 38 ratified parties to meet emissions targets in the commitment period 2008 to 2012.

- The UN summit in Copenhagen in December 2009 where Parties to the UN Framework Convention on Climate Change (UNFCCC) took note of the Copenhagen Accord. The Accord recognizes the scientific view that the increase in global temperature should be below 2°C. Signatories to the Accord are to append to it their emissions targets for 2020 or their proposed GHG mitigation measures. By the end of January 2010 the UNFCCC had received submissions of national pledges to cut and limit greenhouse gases by 2020 from 55 countries. According to the UNFCCC, these countries together account for 78% of global emissions from energy use.

- The European Union (EU) Climate Action and Renewable Energy Package which requires increased greenhouse gas reductions, improvements in energy efficiency and increased renewable energy use by 2020 as well as including the Revision of the EU Emissions Trading Scheme (EU ETS) directive. This regulates approximately one-fifth of our reported 2009 global CO_2 emissions and can be expected to require additional expenditure from 2013 when the revision of the scheme (EU ETS Phase 3) comes into effect.

- Australia has committed to reduce its GHG emissions by between 5-25% below 2000 levels by 2020, depending on the extent of international action. Australia has also developed an emissions trading scheme. If passed in law, it will cover around 70% of the nation s GHG emissions including stationary energy and transport emissions.

- New Zealand has agreed to cut GHG emissions by 10-20% from 1990 levels by 2020, subject to certain conditions. New Zealand is extending the scope of its Emission Trading Scheme in July 2010.

- In the US, recent national legislation has imposed stricter automobile fuel emissions standards and biofuel mandates and legislative proposals would impose GHG emission limits through cap-and-trade programmes as well as mandates for alternative energy and increases in energy efficiency.
  - The US Environmental Protection Agency (EPA) released a GHG endangerment finding in late 2009 giving it authority to regulate GHG emissions under the Clean Air Act; it has also issued a GHG reporting rule covering major stationary emission sources and upstream fuel suppliers.

  - A number of additional state and regional initiatives in the US will affect our operations including regulation in California seeking to reduce GHG emissions to 1990 levels by 2020, including reductions in the carbon intensity of transport fuel sold in the state.

  - Canada has adopted an action plan to reduce emissions to 20% below 2006 levels by 2020 and the national government seeks a coordinated approach with the US on environmental and energy objectives, such as a North America-wide cap-and-trade system.

Each of these measures can increase our production costs for certain products, increase demand for competing energy alternatives or products with lower-carbon intensity and affect the sales of many of our products.

US and EU regulations

Approximately 60% of our fixed assets are located in the US and the EU. US and EU environment and health and safety regulations significantly affect BP s exploration and production, refining, marketing, transportation and shipping operations. Significant legislation in the US and the EU affecting our businesses and profitability includes the following:

United States

The Clean Air Act (CAA) regulates air emissions, permitting, fuel specifications and other aspects of our production, distribution and marketing activities. Stricter limits on sulphur and benzene in fuels will affect us going forward. Additionally, many states have separate laws similar to the CAA.

The Energy Policy Act of 2005 and The Energy Independence and Security Act of 2007 affect our US fuel markets by, among other things, imposing renewable fuel mandate and imposing GHG emission thresholds for certain renewable fuels. States such as California also impose additional carbon fuel standards.

The Clean Water Act (CWA) regulates wastewater and other effluent discharges from BP s facilities, and BP is required to obtain discharge permits, install control equipment and implement operational controls and preventative measures.

The Resource Conservation and Recovery Act (RCRA) regulates the generation, handling, and disposal of wastes associated with our operations and can require corrective action at locations where such wastes have released.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), can, in certain circumstances, impose the entire cost of investigation and remediation on a party who owned or operated a contaminated site or arranged for waste disposal at the site. BP has incurred, or expects to incur, liability under CERCLA or similar state laws, including costs attributed to insolvent or unidentified parties. BP is also subject to claims for remediation costs under other federal and state laws, and to claims for natural resource damages (NRD) under CERCLA, the OPA 90 and other federal and state laws.

The Toxic Substances Control Act regulates BP s import, export and sale of new chemical products.

The Occupational Safety and Health Act (OSHA), imposes workplace safety and health requirements on our operations along with significant process safety management obligations.

The Emergency Planning and Community Right-to-Know Act, requires emergency planning and hazardous substance release notification as well as public disclosure of our chemical usage and emissions.

The US Department of Transportation (DOT) regulates the transport of BP s petroleum products such as crude oil, gasoline and petrochemicals.

The Marine Transportation Security Act and the DOT Hazardous Materials (HAZMAT) and the Chemical Facility Anti-Terrorism Standard (CFATS) regulations impose security compliance regulations on BP and require security vulnerability assessments, security mitigation plans and require security upgrades that increase our cost of operations.

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The US refineries of BP Products North America Inc (BP Products) are subject to a consent decree with the EPA to resolve alleged violations of the CAA and implementation of the decree s requirements continues. A 2009 amendment to the decree resolves remaining alleged air violations at the Texas City refinery through the payment of a $12 million civil fine, a $6 million supplemental environmental project and enhanced CAA compliance measures estimated to cost approximately $150 million. The fine has been paid and BP Products is implementing the other provisions. For further disclosures relating to Texas City refinery, please see Legal proceedings on pages 95-96.

Various environmental groups and the EPA have challenged certain aspects of the operating permit issued by the Indiana Department of Environmental Management (IDEM) for our upgrades to the Whiting refinery. In response to these challenges, IDEM has reviewed the permits and responded formally to the EPA. The EPA either through IDEM or directly can cause the permit to be modified, reissued or in extremis terminated or revoked. BP is in discussions with the EPA and IDEM over these issues and clean air act violations at the Whiting, Toledo, Carson and Cherry Point refineries. Settlement negotiations continue in an effort to resolve these matters.

European Union

BP s operations in the EU are subject to a number of current and proposed regulatory requirements that affect our operations and profitability. These include:

The EU Climate Action and Renewable Energy Package and the Emissions Trading Scheme (ETS) Directive (*see Greenhouse gas regulation above*).

The EU European Integrated Pollution Prevention and Control (IPPC) Directive imposes a unified environmental permit requirement on our major European sites including refineries and chemical facilities and requires assessments and some upgrades to our facilities. A proposed Industrial Emission Directive would replace the IPPC Directive. It would merge several existing industrial emission directives, impose tighter emission standards for large combustion plants and be more prescriptive as to the Best Available Techniques (BAT) to be used to achieve emission limits. This may result in requirements for further emission reductions at our EU sites.

The EC Thematic Strategy on Air Pollution and the related work on revisions to the Gothenburg Protocol and National Emissions Ceiling Directive (NECD). This will establish national ceilings for emissions of a variety of air pollutants in order to achieve EU-wide health and environmental improvement targets. The EC is also considering the use of a NO_X and SO_2 trading scheme as a tool to achieve emission reductions. This may result in requirements for further emission reductions at our EU sites.

The EU Regulation on ozone depleting substances (ODS), which implements the Montreal Protocol on ODS was most recently revised in 2009 requires BP to reduce the use of ozone depleting substances (ODS) and phase out certain ODS substances. BP continues to replace ODS in refrigerants and/or equipment, in the EU and elsewhere, in accordance with the Protocol and related legislation. Methyl bromide (an ODS) is a minor byproduct in the production by our petrochemicals operations of purified terephthalic acid and the progressive phase out of methyl bromide uses may result in future pressure to reduce our emissions of methyl bromide.

The EU Fuel Quality Directive affects our production and marketing of fuels. Proposed changes to this directive would require BP to achieve life cycle GHG emission reductions in fuels we sell and would also facilitate the introduction of biofuels into gasoline and diesel.

The EU Registration, Evaluation and Authorization of Chemicals (REACH) legislation requires that we register chemical substances we manufacture or import into the EU with a complete set of hazard and risk data. Existing manufactured and imported substances were all preregistered by 1 December 2008 and qualified for a timed phase-in for full registration during the period 2010-2018. Crude oil and natural gas are exempt from registration requirements, while fuels are exempt from authorization but not registration. REACH affects our refining, petrochemicals and other manufacturing operations.

International marine fuel regulations under International Maritime Organisation (IMO) and International Convention for the Prevention of Pollution from Ships (Marpol) regimes impose stricter sulphur emission restrictions on ships in EU ports and inland waterways and the North and Baltic seas beginning in 2010 and with a stricter global cap on marine sulphur emissions beginning in 2012. Further reductions are to be phased in thereafter. These restrictions require the use of compliant heavy fuel oil (HFO) or distillate, or the installation of abatement technologies on ships. These regulations will place additional costs on refineries producing marine fuel, including costs to dispose of sulphur, as well as increased CO_2 emissions and energy costs for additional refining.

In the UK, significant health and safety legislation affecting BP includes the Health and Safety at Work Act and regulations and the Control of Major Accident Hazards Regulations.

Maritime regulations

BP Shipping s operations are subject to extensive national and international regulations governing liability, operations, training, spill prevention and insurance. These include:

In US waters, the Oil Pollution Act of 1990 (OPA 90) imposes liability and spill prevention and planning requirements governing, amongst others, tankers, barges and offshore facilities and mandates a levy on oil imported and produced domestically to fund oil spill response. Some states, including Alaska, Washington, Oregon and California, impose additional liability for oil spills.

Outside US territorial waters, BP Shipping tankers are subject to international liability, spill response and preparedness regulations under the UN s International Maritime Organization, including the International Convention on Civil Liability for Oil Pollution, the International Convention for the Prevention of Pollution from Ships, the International Convention on Oil Pollution, Preparedness, Response and Co-operation and the International Convention on Civil Liability for Bunker Oil Pollution Damage.

To meet its financial responsibility requirements, BP Shipping maintains marine liability pollution insurance to a maximum limit of $1 billion for each occurrence through mutual insurance associations (P&I Clubs) but there can be no assurance that a spill will necessarily be adequately covered by insurance or that liabilities will not exceed insurance recoveries.

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Employees

Number of employees at 31 December	US	Non-US	Total
2009			
Exploration and Production	**8,000**	**13,500**	**21,500**
Refining and Marketing[a]	**12,700**	**38,900**	**51,600**
Other businesses and corporate	**2,100**	**5,100**	**7,200**
	22,800	**57,500**	**80,300**
2008			
Exploration and Production	7,700	13,700	21,400
Refining and Marketing[a]	19,000	42,500	61,500
Other businesses and corporate	2,600	6,500	9,100
	29,300	62,700	92,000
2007			
Exploration and Production	7,800	14,000	21,800
Refining and Marketing[a]	22,700	44,500	67,200
Other businesses and corporate	2,500	6,600	9,100
	33,000	65,100	98,100

[a]Includes 13,900 (2008 21,200 and 2007 24,500) service station staff.

People and their capabilities are fundamental to our sustainability as a business. To build an enduring business in an increasingly complex and competitive industry, we need people with world-class capabilities, ranging from deepwater drilling and operating refineries to negotiating with governments and planning wind farms.

We had approximately 80,300 employees at 31 December 2009, compared with approximately 92,000 at 31 December 2008. This reduction principally reflects the transfer of our convenience retail sites to a franchise model and the progress we have made in making BP a simpler, more efficient organization.

Our focus in 2009 has been on ensuring we have the right people in the right roles including renewal of the group leader population. We are seeking to promote continuous improvement by embedding the BP leadership framework throughout the organization. This framework sets out how BP leaders are expected to behave in delivering our strategy and achieving sustained high performance. We are striving for deeper skills development and continuing to align reward frameworks to promote our desired behaviours and outcomes. Diversity and inclusion (D&I) is an important part of all our people processes in BP and involves acknowledging, valuing and leveraging our similarities and differences for business success.

We have made significant progress in changing the culture of the group to one with a stronger performance focus and which places more value on deep specialist skills and expertise. Creating this culture has required us to enhance our approach to performance management at the business, team and individual level and to align performance and reward outcomes.

We have completed the second cycle of our redesigned performance management and reward process to ensure that there is a direct link between performance and incentive reward. Throughout the organization we have also achieved greater differentiation of performance ratings and, as a result, in incentive compensation spend. We believe this will continue to improve the performance focus of businesses and individuals.

In managing our people, we seek to attract, develop and retain highly talented individuals in order to maintain BP s capability to deliver our strategy and plans. Our three-year graduate development programme currently has 1,400 participants from all over the world.

We are focusing on the need for deep specialist skills. Accordingly, we have increased external hiring in infrastructure and technical areas. The energy industry faces a shortage of professionals such as petroleum engineers. The number of experienced workers retiring is expected to exceed that of new graduate hires. To help address this issue we are developing more robust resourcing plans supported by initiatives aimed at increasing the numbers of recruits and diversifying the sources from which we recruit. The external hiring initiatives are supported by plans for accelerated discipline development, prioritized deployment and retention schemes.

The continuous improvement we are making to performance management and reward will help ensure that BP meets the expectations of these new recruits who are highly mobile and whose skills are in high demand.

We aim to ensure equal opportunity in recruitment, career development, promotion, training and reward for all employees, including those with disabilities. Where existing employees become disabled, our policy is to provide continuing employment and training wherever practicable.

We have revitalized our approach to D&I. In 2009, the focus has been to re-establish D&I as a corporate priority. There is now clear ownership by the business of D&I plans which are the direct responsibility of the relevant SPU or function. Each SPU and function has a D&I plan against which progress is measured. In addition the group chief executive chairs the global D&I council. This council is supported by a North American regional council and segment councils. We are creating momentum which we expect will lead to sustainable progress on D&I.

The group people committee, formed in 2007, continues to take overall responsibility for policy decisions relating to employees. In 2009, this included senior level talent review and succession planning, embedding of D&I plans in the businesses and the structure of long-term incentive plans.

We continue to increase the number of local leaders and employees in our operations so that they reflect the communities in which we operate. For example, in Colombia, national employees now make up 98% of BP s team, while in Azerbaijan, the proportion is around 85%. By 2020, more than half our operations are expected to be in non-OECD countries and we see this as an opportunity to develop a new generation of experts and skilled employees.

At the end of 2009, 14% of our top 492 group leaders were female and 21% came from countries other than the UK and the US. When we started tracking the composition of our group leadership in 2000, these percentages were 9% and 14% respectively. We continue to raise our senior leaders awareness of D&I, and further training is planned in 2010.

We aim to develop our leaders internally, although we recruit outside the group when we do not have specialist skills in-house or when exceptional people are available. In 2009, we appointed 40 people to positions in the group leadership population. Of these, 20 were internal candidates.

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The Leadership Framework is being embedded through access to management development programmes and progress will be measured by a new 360° feedback tool. The group-wide management development programme, Managing Essentials Effective Performance Conversations, has now run in 41 countries. A further five programmes have been developed in 2009 which address particular leadership challenges faced by the group leader, senior level leader and first level leader populations.

We provide development opportunities for all our employees, including external and on-the-job training, international assignments, mentoring, team development days, workshops, seminars and online learning. We encourage all employees to take five training days per year.

Through our ShareMatch plan, run in around 65 countries, we match BP shares purchased by employees.

Communications with employees include magazines, intranet sites, DVDs, targeted emails and face-to-face communication. Team meetings are the core of our employee engagement, complemented by formal processes through works councils in parts of Europe. These communications, along with training programmes, are designed to contribute to employee development and motivation by raising awareness of financial, economic, social and environmental factors affecting our performance.

The group seeks to maintain constructive relationships with labour unions.

In 2008, we received feedback through our employee engagement surveys that, while there was still very high loyalty to BP as a company, employee engagement was declining as we worked through the difficult actions needed to turn around our performance. In response, we have made it a priority to ensure that BP s group leaders are better equipped to tell our story and engage their staff in supporting our strategy.

The progress we have made in employee engagement is evident from the results from our 2009 employee survey. The response rate for the survey improved year on year with 57% of people completing the survey, up from 42% in 2008. The Employee Satisfaction Index and our Pulse survey scores for Performance culture and Safety and Compliance culture all improved year on year.

We continue to make significant efforts to communicate the intent and progress of our ongoing cost-efficiency programmes, to minimize any potential negative perceptions within the business. We have moved quickly to manage these people and performance changes while keeping the focus on safety, continuous improvement and sustainable change. These improvements are expected to continue in 2010, but we have already delivered material reductions in complexity, cost and headcount.

The code of conduct

We have a code of conduct designed to ensure that all employees comply with legal requirements and our own standards. The code defines what BP expects of its people in key areas such as safety, workplace behaviour, bribery and corruption and financial integrity. Our employee concerns programme, OpenTalk, enables employees to seek guidance on the code of conduct as well as to report suspected breaches of compliance or other concerns. The number of cases raised through OpenTalk in 2009 was 874, compared with 925 in 2008.

In the US, former US district court judge Stanley Sporkin acts as an ombudsperson. Employees and contractors can contact him confidentially to report any suspected breach of compliance, ethics or the code of conduct, including safety concerns.

We take steps to identify and correct areas of non-compliance and take disciplinary action where appropriate. In 2009, 524 dismissals were reported by BP s businesses for non-compliance or unethical behaviour. This number excludes dismissals of staff employed at our retail service station sites, for incidents such as thefts of small amounts of money.

BP continues to apply a policy that the group will not participate directly in party political activity or make any political contributions, whether in cash or in kind. Specifically, BP made no donations to UK or other EU political parties or organizations in 2009.

Social and community issues

Contributing to communities

We seek to make a positive difference wherever we operate. To do this, we take action that is relevant to local circumstances, mutually beneficial and designed to create enduring, as opposed to short-term, solutions. Our investments in education and local enterprise development aim to build local capability as part of our business agenda, either through our local employees or through the provision of goods and services.

As a global energy company, BP operates in a diverse range of countries and in a variety of environmental and social conditions. A common feature of these operations is the lifespan of our projects some BP projects might last as long as 30-40 years. This longevity requires that BP seeks to cultivate and maintain enduring relationships with the communities and governments in these areas. To do this, BP is committed to finding solutions that create mutual benefit: work with local communities, agencies and organizations on finding solutions to issues that can bring benefit to both the local operations as well as help to meet community development needs over a project s lifespan.

We always seek solutions that are aligned to the strategy of our local businesses. For example, in education we support projects that contribute to the wider sustainable development agenda of the particular country but also develop skills and capabilities that are relevant to BP. In doing this, we involve ourselves, as appropriate, in supporting the enhancement of the availability, quality and relevance of education offerings, particularly technical education. This can range from the development of new geo-science and petro-technical offerings at universities, to the support for English language-based technical training, to the support for a broader understanding of the legal aspects of oil and gas management for policy makers, to the basics of the oil industry for journalists.

In some instances we get involved in supporting elements of macro-economic planning to ensure that issues such as good revenue management practices can enable wider national development. In doing this we usually facilitate access to world class policy thinkers on a range of issues through BP s global relationships with leading education institutions.

We also seek to support the development of the local supply chain as a way of deepening the involvement of local enterprise in BP business activities. The way we do this depends on local conditions but can include training, business advisory services or financing programmes that aim to help develop existing business products and services, improve internal standards and practices, or create new small enterprises.

We support various voluntary, multi-stakeholder initiatives aimed at sharing best practice and improving industry-wide management of key social and economic challenges. We are a member of the Extractive Industries Transparency Initiative (EITI), which supports the creation of a standardized process for transparent reporting of company payments and government revenues from oil, gas and mining. We are also members of the Voluntary Principles on Security and Human Rights through which we have developed a robust internal process designed to ensure that the security of our operations around the world is maintained in a manner consistent with our group stance on human rights.

We make direct contributions to communities through community programmes. Our total contribution in 2009 was $106.8 million, which included $1.3 million to UK charities. The majority of our community expenditure was directed towards education and technical training projects.

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In 2009, we spent $55 million promoting education, with investment in three broad areas: tertiary and post secondary level support for engineering; energy industry-related areas such as geo-science and business leadership skills; and supporting the improvement of science and technology teaching within basic education.

Relationships with suppliers
and contractors

Essential contracts

BP has contractual and other arrangements with numerous third parties in support of its business activities. This report does not contain information about any of these third parties as none of our arrangements with them are considered to be essential to the business of BP.

Suppliers and contractors

Our processes are designed to enable us to choose suppliers carefully on merit, avoiding conflicts of interest and inappropriate gifts and entertainment. We expect suppliers to comply with legal requirements and we seek to do business with suppliers who act in line with BP s commitments to compliance and ethics, as outlined in our code of conduct. We engage with suppliers in a variety of ways, including performance review meetings to identify mutually advantageous ways to improve performance.

Creditor payment policy and practice

Statutory regulations issued under the UK Companies Act 2006 require companies to make a statement of their policy and practice in respect of the payment of trade creditors. In view of the international nature of the group s operations there is no specific group-wide policy in respect of payments to suppliers. Relationships with suppliers are, however, governed by the group s policy commitment to long-term relationships founded on trust and mutual advantage. Within this overall policy, individual operating companies are responsible for agreeing terms and conditions for their business transactions and ensuring that suppliers are aware of the terms of payment.

Regulation of the group s business

BP s activities, including its oil and gas exploration and production, pipelines and transportation, refining and marketing, petrochemicals production, trading, alternative energy and shipping activities, are conducted in many different countries and are therefore subject to a broad range of EU, US, international, regional and local legislation and regulations, including legislation that implements international conventions and protocols. These cover virtually all aspects of our activities and include matters such as licence acquisition, production rates, royalties, environmental, health and safety protection, fuel specifications and transportation, trading, pricing, anti-trust, export, taxes and foreign exchange.

The terms and conditions of the leases, licences and contracts under which our oil and gas interests are held vary from country to country. These leases, licences and contracts are generally granted by or entered into with a government entity or state company and are sometimes entered into with private property owners. These arrangements with governmental or state entities usually take the form of licences or production-sharing agreements (PSAs). Arrangements with private property owners are usually in the form of leases.

Licences (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a licence, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the licence holder is entitled to all production, minus any royalties that are payable in kind. A licence holder is generally required to pay production taxes or royalties, which may be in cash or in kind. Less typically, BP may explore for and exploit hydrocarbons under a service agreement with the host entity in exchange for reimbursement of costs and/or a fee paid in cash rather than production.

PSAs entered into with a government entity or state company generally require BP to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any.

In certain countries, separate licences are required for exploration and production activities and, in certain cases, production licences are limited to a portion of the area covered by the exploration licence. Both exploration and production licences are generally for a specified period of time (except for licences in the US, which typically remain in effect until production ceases). The term of BP s licences and the extent to which these licences may be renewed vary by area.

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

In general, BP is required to pay income tax on income generated from production activities (whether under a licence or PSAs). In addition, depending on the area, BP s production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed on oil and gas production profits and activities may be substantially higher than those imposed on other activities, particularly in Abu Dhabi, Angola, Egypt, Norway, the UK, the US, Russia, South America and Trinidad & Tobago.

For a discussion of environmental and certain health and safety regulations and environmental proceedings, see Environment on pages 43-45. See also Legal proceedings on pages 95-96.

Organizational structure

The significant subsidiaries of the group at 31 December 2009 and the group percentage of ordinary share capital (to the nearest whole number) are set out in Financial statements Note 43 on pages 175-176. See Financial statements Notes 22 and 23 on pages 140 and 141 respectively for information on significant jointly controlled entities and associates of the group.

Business review

Financial performance

Group results

The following summarizes the group s results.

	$ million except per share amounts		
	2009	2008	2007
Sales and other operating revenues	**239,272**	361,143	284,365
Profit for the year	**16,759**	21,666	21,169
Profit for the year attributable to BP shareholders	**16,578**	21,157	20,845
Profit attributable to BP shareholders per ordinary share cents	**88.49**	112.59	108.76
Dividends paid per ordinary share cents	**56.00**	55.05	42.30

For a discussion of the business environment in 2007-2009, see Group overview on page 8.

Profit attributable to BP shareholders

Profit attributable to BP shareholders for the year ended 31 December 2009 was $16,578 million, including inventory holding gains, net of tax, of $2,623 million and a net charge for non-operating items, after tax, of $1,067 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $445 million relative to management s measure of performance. Inventory holding gains and losses, net of tax, are described in footnote (a) below. Further information on non-operating items and fair value accounting effects can be found on pages 54-55.

Profit attributable to BP shareholders for the year ended 31 December 2008 was $21,157 million, including inventory holding losses, net of tax, of $4,436 million and a net charge for non-operating items, after tax, of $796 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $146 million relative to management s measure of performance. Inventory holdings gains or losses, net of tax, are described in footnote (a) below.

Profit attributable to BP shareholders for the year ended 31 December 2007 was $20,845 million, including inventory holding gains, net of tax, of $2,475 million and a net charge for non-operating items, after tax, of $373 million. In addition, fair value accounting effects had an unfavourable impact, net of tax, of $198 million relative to management s measure of performance. Further information on non-operating items and fair value accounting effects can be found on pages 54-55.

The primary additional factors reflected in profit for 2009, compared with 2008, were lower realizations and refining margins and higher depreciation, partly offset by higher production, stronger operational performance and lower costs.

The primary additional factors reflected in profit for 2008, compared with 2007, were higher realizations, a higher contribution from the gas marketing and trading business, improved oil supply and trading performance, improved marketing performance and strong cost management; however, these positive effects were partly offset by weaker refining margins, particularly in the US, higher production taxes, higher depreciation, and adverse foreign exchange impacts.

Profits and margins for the group and for individual business segments can vary significantly from period to period as a result of changes in such factors as oil prices, natural gas prices and refining margins. Accordingly, the results for the current and prior periods do not necessarily reflect trends, nor do they provide indicators of results for future periods.

Employee numbers were approximately 80,300 at 31 December 2009, 92,000 at 31 December 2008 and 98,100 at 31 December 2007.

[a] Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies incurred during the year and the cost of sales calculated on the first-in first-out (FIFO) method including any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on the historic cost of acquisition or manufacture rather than the current replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed represent the difference between the charge to the income statement on a FIFO basis (and any related

movements in net realizable value provisions) and the charge that would arise using average cost of supplies incurred during the period. For this purpose, average cost of supplies incurred during the period is calculated by dividing the total cost of inventory purchased in the period by the number of barrels acquired. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions.

Management believes this information is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due principally to changes in oil prices as well as changes to underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of oil price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, BP s management believes it is helpful to disclose this information.

Capital expenditure and acquisitions

			$ million
	2009	2008	2007
Exploration and Production	**14,696**	22,026	13,904
Refining and Marketing	**4,114**	4,710	4,356
Other businesses and corporate	**1,191**	1,450	934
Capital expenditure	**20,001**	28,186	19,194
Acquisitions and asset exchanges	**308**	2,514	1,447
	20,309	30,700	20,641
Disposals	**(2,681)**	(929)	(4,267)
Net investment	**17,628**	29,771	16,374

Capital expenditure and acquisitions in 2009, 2008 and 2007 amounted to $20,309 million, $30,700 million and $20,641 million respectively. In 2008, this included $4,731 million in respect of our transaction with Husky Energy Inc. and $3,667 million in respect of our purchase of all of Chesapeake Energy Corporation s interest in the Arkoma Basin Woodford Shale assets and the purchase of a 25% interest in Chesapeake s Fayetteville Shale assets. Acquisitions in 2007 included the remaining 31% of the Rotterdam (Nerefco) refinery from Chevron s Netherlands manufacturing company.

Excluding acquisitions and asset exchanges, capital expenditure for 2009 was $20,001 million compared with $28,186 million in 2008 and $19,194 million in 2007.

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Finance costs and net finance expense relating to pensions and other post-retirement benefits

Finance costs comprise interest payable less amounts capitalized, and interest accretion on provisions and long-term other payables. Finance costs in 2009 were $1,110 million compared with $1,547 million in 2008 and $1,393 million in 2007. The decrease in 2009, when compared with 2008, is largely attributable to the reduction in interest rates. The increase in 2008, when compared with 2007, is largely the outcome of reductions in capitalized interest as capital construction projects concluded.

Net finance expense relating to pensions and other post-retirement benefits in 2009 was $192 million compared with net finance income of $591 million and $652 million in 2008 and 2007 respectively. The expected return on assets decreased significantly in 2009 as the pension asset base reduced, consistent with falls in equity markets during 2008.

Taxation

The charge for corporate taxes in 2009 was $8,365 million, compared with $12,617 million in 2008 and $10,442 million in 2007. The effective tax rate was 33% in 2009, 37% in 2008 and 33% in 2007. The group earns income in many countries and, on average, pays taxes at rates higher than the UK statutory rate of 28%. The decrease in the effective tax rate in 2009 compared with 2008 primarily reflects a higher proportion of income from associates and jointly controlled entities where tax is included in the pre-tax operating result, foreign exchange effects and changes to the geographical mix of the group s income. The increase in the effective rate in 2008 compared with 2007 primarily reflects the change in the country mix of the group s income, resulting in a higher overall tax burden.

Segment results

Profit before interest and taxation, which is before finance costs, net finance income or expense, taxation and minority interests, was $26,426 million in 2009, $35,239 million in 2008 and $32,352 million in 2007.

Analysis of replacement cost profit before interest and tax and reconciliation to profit before taxation[a]

			$ million
	2009	2008	2007
By business			
Exploration and Production			
US	**6,685**	11,724	7,929
Non-US	**18,115**	26,584	19,673
	24,800	38,308	27,602
Refining and Marketing			
US	**(2,578)**	(644)	(1,232)
Non-US	**3,321**	4,820	3,853
	743	4,176	2,621
Other businesses and corporate			
US	**(728)**	(902)	(960)

Non-US	**(1,594)**	(321)	(249)
	(2,322)	(1,223)	(1,209)
	23,221	41,261	29,014
Consolidation adjustment	**(717)**	466	(220)
Replacement cost profit before interest and tax[b]	**22,504**	41,727	28,794
Inventory holding gains (losses)			
Exploration and Production	**142**	(393)	127
Refining and Marketing	**3,774**	(6,060)	3,455
Other businesses and corporate	**6**	(35)	(24)
Profit before interest and tax	**26,426**	35,239	32,352
Finance costs	**1,110**	1,547	1,393
Net finance expense (income) relating to pensions and other post-retirement benefits	**192**	(591)	(652)
Profit before taxation	**25,124**	34,283	31,611
Replacement cost profit before interest and tax			
By geographical area			
US	**2,806**	10,678	5,581
Non-US	**19,698**	31,049	23,213
	22,504	41,727	28,794

[a]IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker for the purposes of performance assessment and resource allocation. For BP, this measure of profit or loss is replacement cost profit before interest and tax. In addition, a reconciliation is required between the total of the operating segments measures of profit or loss and the group profit or loss before taxation.

[b]Replacement cost profit reflects the replacement cost of supplies. The replacement cost profit for the period is arrived at by excluding from profit inventory holding gains and losses and their associated tax effect. Replacement cost profit for the group is not a recognized GAAP measure. Further information on inventory holding gains and losses is provided on page 49.

Business review

Exploration and Production

For the year ended 31 December			$ million
	2009	2008	2007
Sales and other operating revenues[a]	**57,626**	86,170	65,740
Replacement cost profit before interest and tax[b]	**24,800**	38,308	27,602
			million barrels of oil equivalent
Net proved reserves for subsidiaries	**12,621**	12,562	12,583
Net proved reserves for equity-accounted entities	**5,671**	5,585	5,231
Total of subsidiaries and equity-accounted entities	**18,292**	18,147	17,814
			$ per barrel
Average BP crude oil realizations[c]	**59.86**	95.43	69.98
Average BP NGL realizations[c]	**29.60**	52.30	46.20
Average BP liquids realizations[c d]	**56.26**	90.20	67.45
Average West Texas Intermediate oil price	**61.92**	100.06	72.20
Average Brent oil price	**61.67**	97.26	72.39
			$ per thousand cubic feet
Average BP natural gas realizations[c]	**3.25**	6.00	4.53
Average BP US natural gas realizations[c]	**3.07**	6.77	5.43
			$ per million British thermal units
Average Henry Hub gas price[e]	**3.99**	9.04	6.86
			pence per therm
Average UK National Balancing Point gas price	**30.85**	58.12	29.95
			thousand barrels per day
Total liquids production for subsidiaries[d f]	**1,400**	1,263	1,304
Total liquids production for equity-accounted entities[d f]	**1,135**	1,138	1,110

Total of subsidiaries and equity-accounted entities[d f]	**2,535**	2,401	2,414
			million cubic feet per day
Natural gas production for subsidiaries[f]	**7,450**	7,277	7,222
Natural gas production for equity-accounted entities[f]	**1,035**	1,057	921
Total of subsidiaries and equity-accounted entities[f]	**8,485**	8,334	8,143
	thousand barrels of oil equivalent per day		
Total production for subsidiaries[f g]	**2,684**	2,517	2,549
Total production for equity-accounted entities[f g]	**1,314**	1,321	1,269
Total of subsidiaries and equity-accounted entities[f g]	**3,998**	3,838	3,818

[a]Includes sales between businesses.

[b]Includes profit after interest and tax of equity-accounted entities.

[c]Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.

[d]Crude oil and natural gas liquids.

[e]Henry Hub First of Month Index.

[f]Net of royalties.

[g]Expressed in thousands of barrels of oil equivalent per day (mboe/d). Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Business review

Sales and other operating revenues for 2009 were $58 billion, compared with $86 billion in 2008 and $66 billion in 2007. The decrease in 2009 primarily reflected lower oil and gas realizations. The increase in 2008 compared with 2007 primarily reflected higher oil and gas realizations; gas marketing sales also increased primarily as a result of higher prices.

The replacement cost profit before interest and tax for the year ended 31 December 2009 was $24,800 million. This included a net credit for non-operating items of $2,265 million (*see page 54*), with the most significant items being gains on the sale of operations (primarily from the disposal of our 46% stake in LukArco, the sale of our 49.9% interest in Kazakhstan Pipeline Ventures LLC and the sale of BP West Java Limited in Indonesia) and fair value gains on embedded derivatives. In addition, fair value accounting effects had a favourable impact of $919 million relative to management s measure of performance (*see page 55*).

The replacement cost profit before interest and tax for the year ended 31 December 2008 was $38,308 million. This included a net charge for non-operating items of $990 million (*see page 54*), with the most significant items being net impairment charges and net fair value losses on embedded derivatives, partly offset by the reversal of certain provisions. The impairment charge included a $517 million write-down of our investment in Rosneft based on its quoted market price at the end of the year. In addition, fair value accounting effects had an unfavourable impact of $282 million relative to management s measure of performance (*see page 55*).

The replacement cost profit before interest and tax for the year ended 31 December 2007 was $27,602 million. This included a net credit from non-operating items of $491 million (*see page 54*), with the most significant items being net gains from the sale of assets (primarily from the disposal of our production and gas infrastructure in the Netherlands, our interests in non-core Permian assets in the US and our interests in the Entrada field in the Gulf of Mexico), partly offset by a restructuring charge and a charge in respect of the reassessment of certain provisions. In addition, fair value accounting effects had a favourable impact of $48 million relative to management s measure of performance (*see page 55*).

The primary additional factor contributing to the 35% decrease in the replacement cost profit before interest and tax for the year ended 31 December 2009 compared with the year ended 31 December 2008 was lower realizations. In addition, the result was impacted by lower income from equity-accounted entities and higher depreciation but the result benefited from higher production and lower costs, as a result of our continued focus on cost management.

The primary additional factor contributing to the 39% increase in the replacement cost profit before interest and tax for the year ended 31 December 2008 compared with the year ended 31 December 2007 was higher realizations. In addition, the result reflected a higher contribution from the gas marketing and trading business but was impacted by higher production taxes and higher depreciation. The impact of inflation within other costs was mitigated by rigorous cost control and a focus on simplification and efficiency.

Reported production for 2009 was 3,998mboe/d (2,684mboe/d for subsidiaries and 1,314mboe/d for equity-accounted entities) compared with 3,838mboe/d in 2008 (2,517mboe/d for subsidiaries and 1,321mboe/d for equity-accounted entities), an increase of 4%. After adjusting for entitlement impacts in our PSAs and the effect of OPEC quota restrictions, the increase was 5%. This reflected continued strong operational performance and the start-up of seven major projects in 2009.

Reported production for 2008 was 3,838mboe/d (2,517mboe/d for subsidiaries and 1,321mboe/d for equity-accounted entities), compared with 3,818mboe/d in 2007 (2,549mboe/d for subsidiaries and 1,269mboe/d for equity-accounted entities). In aggregate, after adjusting for the effect of lower entitlement in our PSAs, 2008 production was 5% higher than 2007. This reflected strong performance from our existing assets, the continued ramp-up of production following the start-up of major projects in late 2007 and the start-up of nine major projects in 2008.

Refining and Marketing

			$ million
	2009	2008	2007
Sales and other operating revenues[a]	**213,050**	320,039	250,221
Replacement cost profit before interest and tax[b]	**743**	4,176	2,621

			$ per barrel
Global indicator refining margin (GIM)[c]			
Northwest Europe	**3.26**	6.72	4.99
US Gulf Coast	**4.63**	6.78	13.48
Midwest	**5.43**	5.17	12.81
US West Coast	**5.88**	7.42	15.05
Singapore	**0.21**	6.30	5.29
BP average	**4.00**	6.50	9.94

			%
Refining availability[d]	**93.6**	88.8	82.9

			thousand barrels per day
Refinery throughputs	**2,287**	2,155	2,127

[a]Includes sales between businesses.

[b]Includes profit after interest and tax of equity-accounted entities.

[c]The global indicator refining margin (GIM) is the average of regional indicator margins weighted 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 regional indicator margins may not be representative of the margins achieved by BP in any period because of BP s particular refinery configurations and crude and product slate.

[d]Refining availability represents Solomon Associates operational availability, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory maintenance downtime.

Business review

Sales and other operating revenues are explained in more detail below.

			$ million
	2009	2008	2007
Sale of crude oil through spot and term contracts	**35,625**	54,901	43,004
Marketing, spot and term sales of refined products	**166,088**	248,561	194,979
Other sales and operating revenues	**11,337**	16,577	12,238
	213,050	320,039	250,221

			thousand barrels per day
Sale of crude oil through spot and term contracts	**1,824**	1,689	1,885
Marketing, spot and term sales of refined products	**5,887**	5,698	5,624

Sales and other operating revenues for 2009 were $213 billion, compared with $320 billion in 2008 and $250 billion in 2007. The decrease in 2009 compared with 2008 primarily reflected a decrease in prices. The increase in 2008 compared with 2007 primarily reflected an increase in revenues from marketing, spot and term sales of refined products, mainly driven by higher prices. Additionally, revenues from sales of crude oil through spot and term contracts increased as a result of higher prices, partly offset by lower volumes.

The replacement cost profit before interest and tax for the year ended 31 December 2009 was $743 million. This included a net charge for non-operating items of $2,603 million (*see page 54*). The most significant non-operating items were restructuring charges and a $1.6 billion one-off, non-cash, loss to impair all the segment s goodwill in the US West Coast fuels value chain relating to our 2000 ARCO acquisition. In addition, fair value accounting effects had an unfavourable impact of $261 million relative to management s measure of performance (*see page 55*).

The replacement cost profit before interest and tax for the year ended 31 December 2008 was $4,176 million. This included a net credit for non-operating items of $347 million (*see page 54*). The most significant non-operating items were net gains on disposal (primarily in respect of the gain recognized on the contribution of the Toledo refinery to a joint venture with Husky Energy Inc.) partly offset by restructuring charges. In addition, fair value accounting effects had a favourable impact of $511 million relative to management s measure of performance (*see page 55*).

The replacement cost profit before interest and tax for the year ended 31 December 2007 was $2,621 million. This included a net charge for non-operating items of $952 million (*see page 54*). The most significant non-operating items were net disposal gains (primarily related to the sale of BP s Coryton refinery in the UK, its interest in the West Texas pipeline system in the US and its interest in the Samsung Petrochemical Company in South Korea), net impairment charges (primarily related to the sale of the majority of our US convenience retail business, a write-down of certain assets at our Hull site in the UK and a write-down of our retail assets in Mexico) and a charge related to the March 2005 Texas City refinery incident. In addition, fair value accounting effects had an unfavourable impact of $357 million relative to management s measure of performance (*see page 55*).

During 2009, our performance was also driven by the significantly weaker environment, where refining margins fell by almost 40%. This was partly offset by significantly stronger operational performance in the fuels value chains, with 93.6% refining availability; lower costs and improved performance in the international businesses.

During 2008, significant performance improvements in both our fuels value chains and international businesses mitigated cost inflation and, to a large extent, the much weaker environment. The main sources of improvement were from restoring the revenues of our refining operations; improved supply and trading performance; improved marketing performance, particularly from the international businesses, and reduced costs. The cost reductions were driven by the simplification of our business structure through the establishment of fuels value chains and a reduction in our geographical footprint, as well as by strong cost management. The most significant environmental factor was the weaker refining environment compared with 2007, particularly due to lower refining margins in the US and the adverse impact in the second half of 2008 of prior-month pricing of domestic pipeline barrels for our US refining system, but there were also adverse foreign exchange effects.

Refining throughputs in 2009 were 2,287mb/d, 132mb/d higher than in 2008. Refining availability was 93.6%, 4.8 percentage points higher than in 2008, the increase being driven primarily by the restoration of availability at our Texas City refinery. Marketing volumes at 3,560mb/d were around 4.1% lower than in 2008.

Other businesses and corporate

			$ million
	2009	2008	2007
Sales and other operating revenues[a]	**2,843**	4,634	3,698
Replacement cost profit (loss) before interest and tax[b]	**(2,322)**	(1,223)	(1,209)

[a] Includes sales between businesses.

[b] Includes profit after interest and tax of equity-accounted entities.

Other businesses and corporate comprises the Alternative Energy business, Shipping, the group s aluminium asset, Treasury (which includes interest income on the group s cash, cash equivalents), and corporate activities worldwide.

The replacement cost loss before interest and tax for the year ended 31 December 2009 was $2,322 million and included a net charge for non-operating items of $489 million (*see page 54*).

The primary additional factors affecting 2009 s result compared with that of 2008 were a weaker margin environment for Shipping and our BP Solar business and adverse foreign exchange effects.

The replacement cost loss before interest and tax for the year ended 31 December 2008 was $1,223 million and included a net charge for non-operating items of $633 million (*see page 54*).

The replacement cost loss before interest and tax for the year ended 31 December 2007 was $1,209 million and included a net charge for non-operating items of $262 million (*see page 54*).

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Non-operating items

Non-operating items are charges and credits arising in consolidated entities that BP discloses separately because it considers such disclosures to be meaningful and relevant to investors. The main categories of non-operating items in the periods presented are: impairments; gains or losses on sale of fixed assets and the sale of businesses; environmental remediation costs; restructuring, integration and rationalization costs; and changes in the fair value of embedded derivatives. These disclosures are provided in order to enable investors better to understand and evaluate the group s financial performance. These items are not separately recognized under IFRS. An analysis of non-operating items is shown in the table below.

			$ million
	2009	2008	2007
Exploration and Production			
Impairment and gain (loss) on sale of businesses and fixed assets	**1,574**	(1,015)	857
Environmental and other provisions	**3**	(12)	(12)
Restructuring, integration and rationalization costs	**(10)**	(57)	(186)
Fair value gain (loss) on embedded derivatives	**664**	(163)	
Other	**34**	257	(168)
	2,265	(990)	491
Refining and Marketing			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**(1,604)**	801	(35)
Environmental and other provisions	**(219)**	(64)	(138)
Restructuring, integration and rationalization costs	**(907)**	(447)	(118)
Fair value gain (loss) on embedded derivatives	**(57)**	57	
Other	**184**		(661)
	(2,603)	347	(952)
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets	**(130)**	(166)	(14)
Environmental and other provisions	**(75)**	(117)	(35)
Restructuring, integration and rationalization costs	**(183)**	(254)	(34)
Fair value gain (loss) on embedded derivatives		(5)	(7)
Other	**(101)**	(91)	(172)
	(489)	(633)	(262)
Total before taxation	**(827)**	(1,276)	(723)
Taxation credit (charge)[b]	**(240)**	480	350

Total after taxation	**(1,067)**	(796)	(373)

[a]Includes $1,579 million in relation to the impairment of goodwill allocated to the US West Coast fuels value chain.

[b]The amounts shown for taxation are based upon the effective tax rate on group profit. In 2009, no tax credit has been calculated on the goodwill impairment in Refining and Marketing because the charge is not tax deductible.

Business review

Non-GAAP information on fair value accounting effects

BP uses derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products as well as certain contracts to supply physical volumes at future dates. Under IFRS, these inventories and contracts are recorded at historic cost and on an accruals basis respectively. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in income because hedge accounting is either not permitted or not followed, principally due to the impracticality of effectiveness testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories and contracts are not recognized until the commodity is sold in a subsequent accounting period. Gains and losses on the related derivative commodity contracts are recognized in the income statement from the time the derivative commodity contract is entered into on a fair value basis using forward prices consistent with the contract maturity.

IFRS requires that inventory held for trading be recorded at its fair value using period end spot prices whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices resulting in measurement differences.

BP enters into contracts for pipelines and storage capacity that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments which are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference for consolidated entities by comparing the IFRS result with management s internal measure of performance, under which the inventory and the supply and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period. We believe that disclosing management s estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole. The impacts of fair value accounting effects, relative to management s internal measure of performance, are shown in the table below. A reconciliation to GAAP information is set out below.

			$ million
	2009	2008	2007
Exploration and Production			
Unrecognized gains (losses) brought forward from previous period	**389**	107	155
Unrecognized (gains) losses carried forward	**530**	(389)	(107)
Favourable (unfavourable) impact relative to management s measure of performance	**919**	(282)	48
Refining and Marketing			
Unrecognized gains (losses) brought forward from previous period	**(82)**	429	72
Unrecognized (gains) losses carried forward	**(179)**	82	(429)

Favourable (unfavourable) impact relative to management s measure of performance	**(261)**	511	(357)
	658	229	(309)
Taxation credit (charge)[a]	**(213)**	(83)	111
	445	146	(198)
By region			
Exploration and Production			
US	**687**	(231)	(77)
Non-US	**232**	(51)	125
	919	(282)	48
Refining and Marketing			
US	**16**	231	(165)
Non-US	**(277)**	280	(192)
	(261)	511	(357)

[a]The amounts shown for taxation are based upon the effective tax rate on group profit.

Reconciliation of non-GAAP information

			$ million
	2009	2008	2007
Exploration and Production			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**23,881**	38,590	27,554
Impact of fair value accounting effects	**919**	(282)	48
Replacement cost profit before interest and tax	**24,800**	38,308	27,602
Refining and Marketing			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**1,004**	3,665	2,978
Impact of fair value accounting effects	**(261)**	511	(357)
Replacement cost profit before interest and tax	**743**	4,176	2,621

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Environmental expenditure

			$ million
	2009	2008	2007
Operating expenditure	**701**	755	662
Clean-ups	**70**	64	62
Capital expenditure	**955**	1,104	1,033
Additions to environmental remediation provision	**588**	270	373
Additions to decommissioning provision	**169**	327	1,163

Operating and capital expenditure on the prevention, control, abatement or elimination of air, water and solid waste pollution is often not incurred as a separately identifiable transaction. Instead, it may form part of a larger transaction that includes, for example, normal maintenance expenditure. The figures for environmental operating and capital expenditure in the table are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

Environmental operating expenditure of $701 million in 2009 was lower than in 2008, due to a reduction in new projects undertaken. In addition, there was a significant reduction in the sulphur oil premium paid due to a greater use of low-sulphur fuel.

Environmental operating expenditure of $755 million in 2008 was higher than in 2007 and reflected continuing integrity management activity. There were no individually significant factors driving the increase.

Similar levels of operating and capital expenditures are expected in the foreseeable future. In addition to operating and capital expenditures, we also create provisions for future environmental remediation. Expenditure against such provisions normally occurs in subsequent periods and is not included in environmental operating expenditure reported for such periods. The charge for environmental remediation provisions in 2009 included $582 million resulting from a reassessment of existing site obligations and $6 million in respect of provisions for new sites.

Provisions for environmental remediation are recognized when a clean-up is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The extent and cost of future environmental restoration, remediation and abatement programmes are inherently difficult to estimate. They often depend on the extent of contamination, and the associated impact and timing of the corrective actions required, technological feasibility and BP s share of liability. Though the costs of future programmes could be significant and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the group s overall results of operations or financial position.

In addition, we recognize provisions on installation of our oil- and gas-producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility a provision is established that represents the discounted value of the expected future cost of decommissioning the asset. Additionally, we undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments. The level of increase in the decommissioning provision varies with the number of new fields coming onstream in a particular year and the outcome of the periodic reviews.

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

Further details of decommissioning and environmental provisions appear in Financial statements Note 34 on page 158. See also Environment on pages 43-45.

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Liquidity and capital resources

Cash flow

The following table summarizes the group s cash flows.

			$ million
	2009	2008	2007
Net cash provided by operating activities	**27,716**	38,095	24,709
Net cash used in investing activities	**(18,133)**	(22,767)	(14,837)
Net cash used in financing activities	**(9,551)**	(10,509)	(9,035)
Currency translation differences relating to cash and cash equivalents	**110**	(184)	135
Increase (decrease) in cash and cash equivalents	**142**	4,635	972
Cash and cash equivalents at beginning of year	**8,197**	3,562	2,590
Cash and cash equivalents at end of year	**8,339**	8,197	3,562

Net cash provided by operating activities for the year ended 31 December 2009 was $27,716 million compared with $38,095 million for 2008 reflecting a decrease in profit before taxation of $9,159 million, an increase in working capital requirements of $8,944 million and a decrease in dividends from jointly controlled entities and associates of $725 million; these were partly offset by a decrease in income taxes paid of $6,500 million, higher depreciation, depletion, amortization and impairment charges of $1,329 million and an increase in charges for provisions of $948 million.

Net cash provided by operating activities for the year ended 31 December 2008 was $38,095 million compared with $24,709 million for 2007 reflecting a decrease in working capital requirements of $11,250 million, an increase in profit before taxation of $2,672 million and an increase in dividends from jointly controlled entities and associates of $1,255 million; these were partly offset by an increase in income taxes paid of $3,752 million.

Net cash used in investing activities was $18,133 million in 2009, compared with $22,767 million and $14,837 million in 2008 and 2007 respectively. The decrease in 2009 reflected a decrease in capital expenditure and acquisitions of $2,356 million and an increase in disposal proceeds of $1,752 million. The increase in 2008 reflected a reduction in disposal proceeds of $3,338 million and an increase in capital expenditure of $5,303 million.

Net cash used in financing activities was $9,551 million in 2009 compared with $10,509 million in 2008 and $9,035 million in 2007. The decrease in 2009 reflects a $2,774 million decrease in the net repurchase of shares and an increase in net proceeds from long-term financing of $1,406 million; these were partly offset by an increase in net repayments of short-term debt of $3,090 million. The increase in 2008 reflects a decrease in short-term debt of $2,809 million and an increase in dividends paid of $2,434 million; these were partly offset by a $4,546 million decrease in the net repurchase of shares.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $21.4 billion in 2009, $23.7 billion in 2008 and $18.4 billion in 2007. Sources of funding are completely fungible, but the majority of the group s funding requirements for new investment come from cash generated by existing operations. The group s level of net debt, that is debt less cash and cash equivalents, was $26.2 billion at the end of 2009, $25.0 billion at the end of 2008 and was $26.8 billion at the end of 2007. During the period 2007 to 2009, our total sources of cash amounted to $100 billion, whilst our total uses of cash amounted to $105 billion. The net cash usage of $5 billion was financed by an increase in finance debt of $11 billion over the three-year period, offset by an increase in our balance of cash and cash equivalents of $6 billion. During this period, the price of Brent has averaged $77.11 per barrel. The following table summarizes the three-year sources and uses of cash.

	$ billion
Sources of cash	
Net cash provided by operating activities	91
Divestments	9
	100
Uses of cash	
Capital expenditure	64
Acquisitions	2
Net repurchase of shares	9
Dividends to BP shareholders	29
Dividends to minority interests	1
	105
Net use of cash	(5)
Financed by	
Increase in finance debt	(11)
Increase in cash and cash equivalents	6
	(5)

Acquisitions made for cash were more than offset by divestment proceeds received during the three-year period. Net investment during the same period averaged $19 billion per year. Dividends to BP shareholders, which grew on average by 14% per year in dollar terms, used $29 billion. Net repurchase of shares was $9 billion, which included $11 billion in respect of our share buyback programme less net proceeds from shares issued in connection with employee share schemes. Finally, cash was used to strengthen the financial condition of certain of our pension plans. In the past three years, $2 billion has been contributed to funded pension plans. This is reflected in net cash provided by operating activities in the table above.

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Trend information

In the US and the major economies of Europe, we expect recovery from the recession to be slow and gradual. The oil markets look well supported by OPEC, but we expect gas markets to remain volatile. Demand for petrochemicals products is recovering only slowly, and there is significant refining over-capacity particularly in the Atlantic Basin. As a consequence, refining margins are likely to remain depressed for the foreseeable future.

In Exploration and Production, production growth was very strong in 2009, benefiting by about 40mboe/d on an annual basis from a combination of the absence of a significant hurricane season and the make-up of a prior-period underlift. As a result, we expect production in 2010 to be slightly lower than in 2009.

In Refining and Marketing, we expect refining margins to remain weak in 2010.

We expect the quarterly loss in Other businesses and corporate, excluding non-operating items, to average around $400 million in 2010. This will, as in previous years, remain volatile on an individual quarterly basis.

We expect capital expenditure, excluding acquisitions and asset exchanges, to be around $20 billion in 2010, and we expect divestments to be between $2 and $3 billion.

In 2009 the cash inflows and outflows of the group were broadly in balance despite much weaker than expected refining margins and North American gas prices. Looking forward we expect to be able to continue to balance cash inflows and outflows even if conditions are equally challenging.

Dividends and other distributions to shareholders

The total dividend paid to BP shareholders in 2009 was $10,483 million, compared with $10,342 million for 2008. The dividend paid per share was 56 cents, an increase of 2% compared with 2008. In sterling terms, the dividend increased 24% due to the strengthening of the dollar relative to sterling. We determine the dividend in US dollars, the economic currency of BP.

During 2009, the company did not repurchase any of its own shares.

Our aim is to strike the right balance for shareholders, between current returns via the dividend, sustained investment for long-term growth, and maintaining a prudent gearing level. At the beginning of 2008, we rebalanced our distributions away from share buybacks in favour of dividends.

Subject to shareholder approval at the Annual General Meeting on 15 April, an optional scrip dividend programme, allowing shareholders to choose to receive dividends in the form of new fully paid ordinary shares in BP p.l.c. instead of cash, will be available for future dividends. This would replace the company s current dividend reinvestment plans.

The discussion above and following contains forward-looking statements particularly those regarding global economic recovery and outlook for oil and gas markets, oil and gas prices, refining margins, production, demand for petrochemicals products, underlying average quarterly loss from Other businesses and corporate, effective tax rate, operating and capital expenditure, timing and proceeds of divestments, contractual commitments, balance of cash inflows and outflows and dividend and optional scrip dividend. These forward-looking statements are based on assumptions that management believes to be reasonable in the light of the group s operational and financial experience. However, no assurance can be given that the forward-looking statements will be realized. You are urged to read the cautionary statement under Forward-looking statements on page 17 and Risk factors on pages 14-16, which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements. The company provides no commitment to update the forward-looking statements or to publish financial projections for forward-looking statements in the future.

Financing the group s activities

The group s principal commodity, oil, is priced internationally in US dollars. Group policy has been to minimize economic exposure to currency movements by financing operations with US dollar debt wherever possible, otherwise by using currency swaps when funds have been raised in currencies other than US dollars.

The group s finance debt is almost entirely in US dollars and at

31 December 2009 amounted to $34,627 million (2008 $33,204 million) of which $9,109 million (2008 $15,740 million) was short term.

Net debt was $26,161 million at the end of 2009, an increase of $1,120 million compared with 2008. We believe that a net debt ratio, that is net debt to net debt plus equity, of 20-30% provides an efficient capital structure and the appropriate level of financial flexibility. The net debt ratio was 20% at the end of 2009 and 21% at the end of 2008, the lower end of our target band. Net debt, which BP uses as a measure of financial gearing, includes the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is claimed.

The maturity profile and fixed/floating rate characteristics of the group s debt are described in Financial statements Note 24 on page 142 and Note 32 on page 156.

We have in place a European Debt Issuance Programme (DIP) under which the group may raise $20 billion of debt for maturities of one month or longer. At 31 December 2009, the amount drawn down against the DIP was $11,403 million (2008 $10,334 million).

In addition, the group has in place an unlimited US Shelf Registration under which it may raise debt with maturities of one month or longer.

Commercial paper markets in the US and Europe are a primary source of liquidity for the group. At 31 December 2009, the outstanding commercial paper amounted to $398 million (2008 $4,268 million).

The group also has access to significant sources of liquidity in the form of committed facilities and other funding through the capital markets. At 31 December 2009, the group had available undrawn committed borrowing facilities of $4,950 million (2008 $4,950 million).

BP believes that, taking into account the substantial amounts of undrawn borrowing facilities available, the group has sufficient working capital for foreseeable requirements.

Off-balance sheet arrangements

At 31 December 2009, the group s share of third-party finance debt of equity-accounted entities was $6,483 million (2008 $6,675 million). These amounts are not reflected in the group s debt on the balance sheet.

The group has issued third-party guarantees under which amounts outstanding at 31 December 2009 are $319 million (2008 $223 million) in respect of liabilities of jointly controlled entities and associates and $667 million (2008 $613 million) in respect of liabilities of other third parties. Of these amounts, $286 million (2008 $215 million) of the jointly controlled entities and associates guarantees relate to borrowings and for other third-party guarantees, $633 million (2008 $582 million) relates to guarantees of borrowings.

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Contractual commitments

The following table summarizes the group s principal contractual obligations at 31 December 2009. Further information on borrowings and finance leases is given in Financial statements Note 32 on page 156 and more information on operating leases is given in Financial statements Note 12 on page 132.

$ million

Expected payments by period under contractual obligations and commercial commitments	Total	2010	2011	2012	2013	2014	2015 and thereafter
							Payments due by period
Borrowings[a]	36,717	9,681	6,740	5,282	5,463	3,085	6,466
Finance lease future minimum lease payments	845	109	121	77	65	66	407
Operating leases[b]	14,716	3,251	2,513	1,977	1,604	1,240	4,131
Decommissioning liabilities	13,261	364	261	356	428	389	11,463
Environmental liabilities	1,860	385	256	193	152	117	757
Pensions and other post-retirement benefits[c]	26,855	1,647	1,890	1,887	1,884	1,491	18,056
Unconditional purchase obligations[d]	155,356	92,536	16,189	10,420	6,677	5,350	24,184
Total	249,610	107,973	27,970	20,192	16,273	11,738	65,464

[a] Expected payments include interest payments on borrowings totalling $2,679 million ($662 million in 2010, $508 million in 2011, $379 million in 2012, $262 million in 2013, $168 million in 2014 and $700 million thereafter).

[b] The future minimum lease payments are before deducting related rental income from operating sub-leases. In the case of an operating lease entered into solely by BP as the operator of a jointly controlled asset, the amounts shown in the table represent the net future minimum lease payments, after deducting amounts reimbursed, or to be reimbursed, by joint venture partners. Where BP is not the operator of a jointly controlled asset BP s share of the future minimum lease payments are included in the amounts shown, whether BP has co-signed the lease or not. Where operating lease costs are incurred in relation to the hire of equipment used in connection with a capital project, some or all of the cost may be capitalized as part of the capital cost of the project.

[c] Represents the expected future contributions to funded pension plans and payments by the group for unfunded pension plans and the expected future payments for other post-retirement benefits.

[d] Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2010 include purchase commitments existing at 31 December 2009 entered into principally to meet the group s short-term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Financial statements Note 24 on page 142.

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

$ million

Unconditional purchase obligations	Total	2010	2011	2012	2013	2014	Payments due by period 2015 and thereafter
Crude oil and oil products	80,991	62,794	6,352	3,894	1,787	1,001	5,163
Natural gas	41,680	21,038	5,598	3,150	2,386	1,957	7,551
Chemicals and other refinery feedstocks	10,939	2,909	1,521	1,183	849	824	3,653
Power	3,846	2,969	591	236	36	14	
Utilities	718	112	111	93	69	59	274
Transportation	8,923	1,005	858	806	766	723	4,765
Use of facilities and services	8,259	1,709	1,158	1,058	784	772	2,778
Total	155,356	92,536	16,189	10,420	6,677	5,350	24,184

The group expects its total capital expenditure, excluding acquisitions and asset exchanges, to be around $20 billion in 2010. The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2009 and the proportion of that expenditure for which contracts have been placed. Capital expenditure is considered to be committed when the project has received the appropriate level of internal management approval. For jointly controlled assets, the net BP share is included in the amounts shown. Where operating lease costs are incurred in connection with a capital project, some or all of the cost may be capitalized as part of the capital cost of the project. Such costs are included in the amounts shown.

Capital expenditure commitments	Total	2010	2011	2012	2013	2014	$ million 2015 and thereafter
Committed on major projects	29,451	13,406	7,071	3,091	1,624	1,618	2,641
Amounts for which contracts have been placed	9,812	6,611	1,713	748	320	195	225

In addition, at 31 December 2009, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $1,038 million. Contracts were in place for $792 million of this total.

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Board performance and biographies

Directors and senior management
The following lists the company s directors and senior management as at 18 February 2010.

Name		Initially elected or appointed
C-H Svanberg	Chairman	Chairman since January 2010 Director since September 2009
Sir Ian Prosser	Non-Executive Deputy Chairman	Deputy chairman since February 1999 Director since May 1997
P Anderson	Non-Executive Director	February 2010
A Burgmans	Non-Executive Director	February 2004
C B Carroll	Non-Executive Director	June 2007
Sir William Castell	Non-Executive Director	July 2006
G David	Non-Executive Director	February 2008
E B Davis, Jr	Non-Executive Director	December 1998
D J Flint	Non-Executive Director	January 2005
Dr D S Julius	Non-Executive Director	November 2001
Dr A B Hayward	Executive Director (Group Chief Executive)	Group Chief Executive since May 2007 Director since February 2003
I C Conn	Executive Director (Chief Executive, Refining and Marketing)	July 2004
R W Dudley	Executive Director (Managing Director)	April 2009
Dr B E Grote	Executive Director (Chief Financial Officer)	August 2000
A G Inglis	Executive Director (Chief Executive, Exploration and Production)	February 2007
R Bondy	Group General Counsel	May 2008
S Bott	Executive Vice President, Human Resources	March 2005
H L McKay	Executive Vice President (Chairman and President of BP America Inc.)	June 2008
S Westwell	Executive Vice President (Group Chief of Staff)	January 2008

Mr C-H Svanberg was appointed as a director and chairman designate on 1 September 2009 and appointed chairman on 1 January 2010 on the retirement of Mr P D Sutherland. Mr P Anderson was appointed as a director on 1 February 2010. Sir Tom McKillop resigned as a director on 16 April 2009.
At the company s 2009 annual general meeting (AGM), the following directors retired, offered themselves for election/re-election and were duly elected/re-elected: Mr A Burgmans; Mrs C B Carroll; Sir William Castell; Mr I C Conn; Mr G David; Mr E B Davis, Jr; Mr R W Dudley; Mr D J Flint; Dr B E Grote; Dr A B Hayward; Mr A G Inglis; Dr D S Julius; Sir Ian Prosser and Mr P D Sutherland.
Mr I E L Davis has been appointed as a director with effect from 2 April 2010. All of the directors, including Mr Davis, will offer themselves for election/re-election at the company s 2010 AGM.
David Jackson (57) was appointed company secretary in 2003. A solicitor, he is a director of BP Pension Trustees Limited and a member of the Listing Authorities Advisory Committee.

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Directors

C-H Svanberg

Chairman of the chairman s and the nomination committees and attends meetings of the remuneration committee

Carl-Henric Svanberg (57) was appointed a non-executive director of BP on 1 September 2009 and, in succession to Mr Sutherland, became chairman of BP on 1 January 2010. From 2003 until 31 December 2009, he was president and chief executive officer of Ericsson, also serving as the chairman of Sony Ericsson Mobile Communications AB. He continues to be a non-executive director of Ericsson.

Sir Ian Prosser

Member of the chairman s, the nomination and the remuneration committees and chairman of the audit committee

Sir Ian (66) joined BP s board in 1997 and was appointed non-executive deputy chairman in 1999. He is the senior independent director. In 2003, he retired as chairman of InterContinental Hotels Group PLC, a spin-off from the former Bass PLC where he was chief executive. He is a non-executive director of the Sara Lee Corporation and non-executive chairman of The Navy, Army and Air Force Institutes (NAAFI). He was previously on the boards of GlaxoSmithKline plc, The Boots Company PLC and Lloyds TSB PLC.

P Anderson

Member of the chairman s and the safety, ethics and environment assurance committees

Paul Anderson (64) was appointed a non-executive director of BP on 1 February 2010. He is a non-executive director of BAE Systems PLC and of Spectra Energy Corp. He was formerly chief executive at BHP Billiton and Duke Energy where he also served as a non-executive director. Having previously been chief executive officer and managing director of BHP Limited and then BHP Billiton Limited and BHP Billiton Plc, he rejoined these latter boards in 2006 as a non-executive director, retiring on 31 January 2010.

A Burgmans, KBE

Member of the chairman s, the remuneration and the safety, ethics and environment assurance committees

Antony Burgmans (63) joined BP s board in 2004. He was appointed to the board of Unilever in 1991. In 1999, he became chairman of Unilever NV and vice chairman of Unilever PLC. In 2005, he became non-executive chairman of Unilever PLC and Unilever NV, retiring from these appointments in 2007. He is also a member of the supervisory boards of Akzo Nobel NV, Aegon NV and SHV Holdings NV.

C B Carroll

Member of the chairman s and the safety, ethics and environment assurance committees

Cynthia Carroll (53) joined BP s board in 2007. She started her career at Amoco and in 1989 she joined Alcan, where in 2002 she was appointed president and chief executive officer of Alcan s primary metals group and an officer of Alcan, Inc. She was appointed as chief executive of Anglo American plc, the global mining group, in 2007. She is also a director of De Beers s.a. and Anglo Platinum Ltd.

Sir William Castell, LVO

Member of the chairman s and the nomination committees and chairman of the safety, ethics and environment assurance committee

Sir William (62) joined BP s board in 2006. From 1990 to 2004, he was chief executive of Amersham plc and subsequently president and chief executive officer of GE Healthcare. He was appointed as a vice chairman of the board of GE in 2004, stepping down from this post in 2006 when he became chairman of the Wellcome Trust. He remains a non-executive director of GE.

G David

Member of the chairman s, the audit and the remuneration committees

George David (67) joined BP s board in February 2008. He has spent his career with United Technologies Corporation (UTC), as its chief executive officer between 1994 and 2008 and chairman from 1997 until his retirement on 31 December 2009. He is a former director of Citigroup Inc.

E B Davis, Jr

Member of the chairman s, the audit and the safety, ethics and environment assurance committees

Erroll B Davis, Jr (65) joined BP s board in 1998, having previously been a director of Amoco. He was chairman and chief executive officer of Alliant Energy, relinquishing this dual appointment in 2005. He continued as chairman of Alliant Energy until 2006, leaving to become chancellor of the University System of Georgia. He is a member of the board of General Motors Corporation and Union Pacific Corporation.

D J Flint, CBE

Member of the chairman s and the audit committees

Douglas Flint (54) joined BP s board in 2005. He trained as a chartered accountant and was made a partner at KPMG in 1988. In 1995, he was appointed group finance director of HSBC Holdings plc and in 2009 his role was broadened to chief financial officer, executive director risk and regulation. He was chairman of the Financial Reporting Council s review of the Turnbull Guidance on Internal Control. Between 2001 and 2004, he served on the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board.

Dr D S Julius, CBE

Member of the chairman s and the nomination committees and chairman of the remuneration committee

DeAnne Julius (60) joined BP s board in 2001. She began her career as a project economist with the World Bank in Washington. From 1986 until 1997, she held a succession of posts, including chief economist at British Airways and Royal Dutch Shell Group. From 1997 to 2001, she was a full time member of the Monetary Policy Committee of the Bank of England. She is chairman of the Royal Institute of International Affairs and a non-executive director of Roche Holdings SA and Jones Lang LaSalle, Inc.

Dr A B Hayward

Tony Hayward (52) joined BP in 1982. He held a series of roles in exploration and production, becoming a director of exploration and production in 1997. In 2000, he was made group treasurer, and an executive vice president in 2002. He was chief executive officer of exploration and production between 2002 and 2007. He became an executive director of BP in 2003 and was appointed as group chief executive in 2007.

I C Conn

Iain Conn (47) joined BP in 1986. Following a variety of roles in oil trading, commercial refining, retail and commercial marketing operations, and exploration and production, in 2000 he became group vice president of BP s refining and marketing business. From 2002 to 2004, he was chief executive of petrochemicals. He was appointed group executive officer with a range of regional and functional responsibilities and an executive director in 2004. He was appointed chief executive of refining and marketing in 2007. He is a non-executive director and senior independent director of Rolls-Royce Group plc.

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Board performance and biographies

R W Dudley
Robert Dudley (54) joined the Amoco Corporation in 1979 for whom he worked until its merger with BP in 1998. Following a variety of posts in the US, the UK, the South China Sea and Moscow, in 2001 he became group vice president responsible for BP s upstream businesses in Russia, the Caspian Region, Angola, Algeria and Egypt. From 2003 to 2008, Mr Dudley was president and chief executive officer of TNK-BP in Moscow. He was appointed an executive director on 6 April 2009 and is an executive vice president with responsibility for broad oversight of the company s activities in the Americas and Asia.

Dr B E Grote
Byron Grote (61) joined BP in 1987 following the acquisition of The Standard Oil Company of Ohio, where he had worked since 1979. He became group treasurer in 1992 and in 1994 regional chief executive in Latin America. In 1999, he was appointed an executive vice president of exploration and production, and chief executive of chemicals in 2000. He was appointed an executive director of BP in 2000 and chief financial officer in 2002. He is a non-executive director of Unilever NV and Unilever PLC.

A G Inglis
Andy Inglis (50) joined BP in 1980, working on various North Sea projects. Following a series of commercial roles in exploration, in 1996, he became chief of staff, exploration and production. From 1997 until 1999, he was responsible for leading BP s activities in the deepwater Gulf of Mexico. In 1999, he was appointed vice president of BP s US western gas business unit. In 2004, he became executive vice president and deputy chief executive of exploration and production. He was appointed chief executive of BP s exploration and production business and an executive director in 2007. He is a non-executive director of BAE Systems plc.

Senior management

R Bondy
Rupert Bondy (48) joined BP as group general counsel in May 2008. In 1989, he joined US law firm Morrison & Foerster, working in San Francisco and London. From 1994 to 1995, he worked for UK law firm Lovells in London. In 1995, he joined SmithKline Beecham as senior counsel for mergers and acquisitions and other corporate matters. He subsequently held positions of increasing responsibility and following the merger of SmithKline Beecham and GlaxoWellcome he was appointed senior vice president and general counsel of GlaxoSmithKline in 2001.

S Bott
Sally Bott (60) joined BP in 2005 as an executive vice president responsible for global human resources. Sally joined Citibank in 1970 and was in the economics department and the finance function before joining human resources. She was appointed human resources vice president in 1979. In 1994, she joined Barclays De Zoete Wedd, an investment bank, as head of human resources and in 1997 became group human resources director of Barclays plc. From 2000 to early 2005, she was managing director of Marsh and McLennan and head of global human resources at Marsh Inc. In 2008, Sally was elected as a non-executive director of UBS AG.

H L McKay
Lamar McKay (51) was appointed chairman and president of BP America, Inc. in February 2009. He joined Amoco Production Company as a petroleum engineer in 1980. He held a variety of roles before becoming group vice president for Russia & Kazakhstan in 2003, also being appointed to the board of TNK-BP in 2004. In 2007, he was named executive vice-president of BP America and COO. In early 2008, he became executive vice president of BP plc special projects, focusing on Russia, subsequently joining the group executive management team in June 2008.

S Westwell
Steve Westwell (51) joined BP in the manufacturing and supply division of BP Southern Africa in 1988. Following various retail positions in the UK and the US, he was appointed head of retail and a member of the board of BP Southern Africa Pty. In 2003, he became president and chief executive officer of BP solar, and in 2004, group vice president of natural gas liquids, power, solar and renewables. In 2005, he was appointed group vice president of alternative energy. He was appointed group chief of staff in January 2008.

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Board performance and biographies

Board performance report

I am pleased to have this opportunity to report to you on the work of the BP board over the last year.

I joined the board as a non-executive director in September 2009 and took the chair on 1 January 2010 upon the retirement of Peter Sutherland. Peter has reviewed this letter and I, of course, have had the benefit of the views of my board colleagues on its content.

This is a particularly interesting time for me to take the chair at BP. In the past months we have seen the reports of Sir David Walker and the Financial Reporting Council (FRC), to which we have contributed. The way in which boards work has again been in the spotlight. There are a number of lessons that all boards can learn from the events of 2008 and 2009. Both these reports have focused on the need for appropriate behaviours around the board table and for governance not to be regarded as solely relating to compliance. This is a view which BP has taken for some time and which I fully endorse.

I have been impressed by BP s commitment to the highest standards of corporate governance. Governance describes all that a board does a point which has been reinforced by the FRC s draft revised Combined Code. It is vital that a board balances the time that it spends between strategy and oversight. From early indications, I believe that the BP board achieves this balance well.

The board is responsible for the direction and oversight of BP p.l.c. on behalf of shareholders; it is accountable to them, as owners, for all aspects of BP s business. It sets the tone from the top. In conducting its business, BP needs to be responsive to other constituencies with whom it comes into contact.

Governance framework

Clarity of roles and responsibilities, and the proper utilization of distinct skills and processes lie at the heart of the board s role. The BP board governance principles (principles) are the framework within which the board operates.

This framework sets out the role of the board, its processes, its relationship with executive management and the main tasks and requirements of the board committees. The board s core activities include:

- The active consideration of long-term strategy.
- The monitoring of executive action and the performance of BP.
- Obtaining assurance that the material risks to BP are identified and that systems of risk management and control are in place to mitigate such risks.
- Ongoing board and executive management succession.

The principles can be seen on BP s website at *www.bp.com/governance*.

The board delegates authority for executive management of the company to the group chief executive. This delegation is subject to a clearly defined set of executive limitations which are monitored by the board. The executive limitations require the group chief executive to take into consideration specific issues in the course of business these include key risk areas such as health, safety and environmental matters and generally ensuring that BP s reputation is maintained. The group chief executive is also responsible for ensuring there is a comprehensive system of controls to identify and manage the risks that are material to BP.

The board keeps this framework under regular review and tests its effectiveness through the annual board evaluation.

Board activities in 2009

The board s work reflects the tasks described above, namely strategy, risk and the oversight of the company s performance and operation of the system of delegation.

The board endeavours to balance its work so that these tasks are achieved either through the work of the board or its committees. At the start of each year, the board reviews and agrees a forward workplan based upon:

- The need for the board to be involved in strategy development and the oversight of risk.

Annual reviews of the two business segments and of the corporate business and functions which includes Alternative Energy.

Oversight of risk generally and specifically those risks identified through the annual plan (the board will decide which risk issues will be considered by the whole board and which will be delegated to the committees with appropriate reporting to the board).

Consideration of quarterly and annual corporate reporting documentation.

In determining its programme the board has to allow sufficient time for urgent issues to be accommodated. The board will meet by telephone should circumstances dictate.

The board now holds one of its meetings at the company s offices in Washington and will meet at other locations when appropriate. In 2009, the board met in Long Beach, California and used this opportunity to visit the company s businesses in the West Coast fuels value chain and to learn about the research taking place into biofuels.

An analysis of the time spent by the board during 2009 is shown below:

Strategy and risk

While strategic issues are normally discussed at the two dedicated away day sessions, the development of the group s business over the year has meant that strategic issues have been actively considered at a number of meetings. Strategic and geopolitical challenges, together with the associated risks are at the core of the group s business.

The business and competitive environment, the global economic outlook, the impact of the price of oil, the issues raised by carbon policy, the technological challenges and strengths of the group were all matters which the board kept under review.

Board performance and biographies

GCE update and business reviews

The group chief executive provides a written report to each meeting of the board which gives an update on key issues relating to safety and integrity, operations, financial performance and the market in which BP s businesses operate. These are complemented by verbal updates given by executive directors on material matters which have arisen in their business.

Periodic reviews of the business are scheduled throughout the year. During 2009, reviews were held with both segments (Exploration and Production and Refining and Marketing) and with Alternative Energy.

Country specific reports

Separate to the business specific reports, the board discussed the performance, political landscape and market outlook relating to BP s operations, particularly in the US and Russia.

Functional reviews

The work of the group technology function was reviewed and discussions were held on issues relating to information technology and services.

Financial and corporate reporting

The board considered the group s statutory reports and the broader aspects of corporate reporting. It also received regular updates on the group s financial outlook as well as discussing the financial results.

An annual review of the group s process for sanctioning capital investment is undertaken by the board. This includes examining case studies of BP projects with different levels of complexity and understanding the effectiveness of project delivery against original sanction.

Other matters

Other matters discussed by the board included the BP brand and corporate advertising, the results of the group-wide employee satisfaction survey and an annual report evaluating BP s external reputation in the UK and US.

The board also received a presentation from the independent expert appointed to provide an objective assessment of the BP US Refineries Independent Safety Review Panel (the panel). Further details on the activities of the independent expert are outlined in the report of the safety, ethics and environment assurance committee below.

Risk management and internal control

The board and its committees monitor the identification and management of the group s risks and the board reviews how group-level risks and their mitigations are embedded in the company s annual plan. Geopolitical and reputational risks are considered by all the board which also receives reports from the committees to whom specific risk oversight has been allocated. The audit committee monitors financial risk whilst the safety, ethics and environment assurance committee (SEEAC) monitors non-financial risk; the audit committee and SEEAC hold an annual joint meeting to assess the effectiveness of the company s internal controls and risk management. Like BP s other board committees, the audit committee and SEEAC are composed entirely of independent non-executive directors.

The audit committee and SEEAC maintain a forward-looking approach to risk exposure. A high level work programme for the board and its committees is set on the basis of an agenda that reflects the board s core tasks and the key group risks.

The group chief executive and his senior team are supported by executive-level sub-committees which monitor specific group risks: these committees comprise the group operations risk committee (GORC), the group financial risk committee (GFRC), the group people committee (GPC), the resource commitments meeting (RCM) and the group disclosures committee (GDC). They provide input and data to the risk oversight process by the executive, as well as external and internal audit, the group s compliance and ethics officer, safety and operations audit and group controls.

Further information about our internal control systems is set out on pages 16, 70 and 101.

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Board performance and biographies

BP s general auditor (head of the internal audit function) reports on the design and operation of risk management activities across the group and attends meetings of both the audit committee and SEEAC. The general auditor has direct access to the chairs of both committees and holds regular meetings with them outside formal meetings.

Within the company, BP has an annual certification process in which team leaders are asked to discuss with their teams and then submit a certificate regarding their and their team s understanding of and adherence to BP s code of conduct and the reporting of any breaches or risk of non-compliance. The certification system enables the risk of non-compliance to be assessed and reported alongside other business risks.

Board meetings and attendance

The board met 12 times during the year, of which two meetings were two-day strategy sessions and three meetings were by telephone.

	Board meetings eligible to attend	Board meetings attended
P D Sutherland	12	10
Sir Ian Prosser	12	12
A Burgmans	12	12
C B Carroll	12	11
Sir William Castell	12	11
G David	12	12
E B Davis, Jr	12	10
D J Flint	12	10
D S Julius	12	12
Sir Tom McKillop[a]	5	3
C-H Svanberg[b]	4	3
I C Conn	12	12
R W Dudley[c]	8	8
B E Grote	12	12
A B Hayward	12	12
A G Inglis	12	11

[a]Retired from the board on 16 April 2009.
[b]Joined the board on 1 September 2009.
[c]Joined the board on 6 April 2009.

International advisory board

In 2009, BP formed an international advisory board whose purpose is to advise the chairman, group chief executive and board of BP plc on strategic and geopolitical issues relating to the long-term development of the company. The international advisory board met twice in 2009.

The chairman, senior independent director and non-executive directors

Neither the chairman nor the senior independent director is employed as an executive of the group. The board is required to develop and maintain a plan for the succession of both the chairman and senior independent director. During 2009, these posts were held by Peter Sutherland and Sir Ian Prosser respectively. Sir Ian Prosser also held the post of deputy chairman during the year a role which will cease on his retirement.

The chairman

Upon Peter s retirement, I took the chair on 1 January 2010. The process for my appointment and induction programme is outlined below. I stepped down as CEO of Ericsson on 31 December 2009, but will remain on the Ericsson board as a non-executive director. I had no other significant commitments at the time of my appointment as chairman.

The chairman s role is to provide leadership of the board, act as facilitator for meetings, maintain the integrity of the governance framework and have overall responsibility for ensuring the board s effectiveness. Other responsibilities include leading the board s performance evaluation and overseeing the board learning and induction programme. The chairman is tasked with setting the agenda for the board in consultation with the group chief executive and with the support of the company secretary. The chairman ensures that systems are in place to provide directors with accurate, timely and clear information concerning the business of the board and the company.

Between board meetings, the chairman has authority to act and speak for the board on all matters relating to the role of the board. He also has responsibility for ensuring the relationship with executive management is working well.

The chairman represents the views of the board to shareholders on key issues, in particular those relating to the work of the board including succession planning. He keeps the board briefed on those views. In November I was able to meet a number of our institutional shareholders as part of my induction. I found these to be productive meetings and comment on them, and on the board engagement which has taken place during the year, in further detail below.

The senior independent director

The senior independent director acts for the chairman in his absence or at his request, and is available to shareholders if they request a meeting or have concerns which contact through the normal channels has failed to resolve or where such contact is inappropriate.

The senior independent director is available to act as a communication channel between the chairman and other board members and, when necessary, to provide a sounding board for the chairman. He also has responsibility for leading the annual performance review of the chairman.

Sir Ian Prosser will retire from the BP board at the AGM in April 2010. Sir William Castell will become the senior independent director from that date.

Sessions of the non-executive directors

The chairman and all non-executive directors meet periodically without the presence of executive management as the chairman s committee. The work of the committee during the year is outlined in the report below.

Board composition

During the year, the number on the board has fluctuated. As at 26 February 2010, the board is composed of the chairman, nine non-executive directors and five executive directors; over half the board is therefore made up of independent non-executive directors. We state that the number of directors should not normally exceed 16.

This is a large board, however, given the scale and scope of BP s business we believe that it is appropriate. We need to have a broad and experienced group of directors who are able to contribute to a discussion on strategy and risk whilst having the right skills to work on the committees. We believe it is important to have a strong group of executive directors who recognize their board responsibilities as directors and not solely to represent the activity in the company for which they are responsible. This adds to open and constructive debate and demonstrates one of the strengths of a unitary board.

Sir Tom McKillop retired from the board on 16 April 2009 and Peter Sutherland retired on 31 December 2009. Bob Dudley joined the board as an executive director on 6 April 2009 and I became a BP non-executive director and chairman designate on 1 September 2009. Paul Anderson joined the board on 1 February 2010 and Ian Davis will join the board on 2 April 2010. Finally, two of our longest serving directors will be retiring at the AGM in April 2010: Sir Ian Prosser and Erroll Davis, Jr.

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Board performance and biographies

Appointments to the board

The board is actively involved in succession planning for both executive and non-executive directors. It is assisted in this task of the progressive refreshing of the board by the nomination committee. The nomination committee keeps under review the composition, skills, independence, knowledge and diversity of directors to ensure that the board and its committees remains effective and appropriate to the work they undertake. This review is undertaken at regular intervals and forms the basis of criteria to evaluate potential board candidates.

Due to the size of the BP board and the wish to achieve a steady refreshment of board appointments the nomination committee is developing a longer-term pipeline of potential non-executive talent on which it hopes to draw as new appointments arise. The committee believes that given BP s scale and breadth of operations, a broad mix of skills, experience and knowledge is required for its board members. The committee has identified deep operational and industry experience, as well as insight into key technologies, health and safety, emerging markets and financial knowledge as particularly relevant to future board appointments. An understanding of geopolitical influence is also a key skill.

A report on the work of the nomination committee is set out below.

Terms of appointment

The chairman and non-executive directors of BP serve on the basis of letters of appointment. Non-executive directors ordinarily retire at the AGM following their 70th birthday. Executive directors have service contracts with the company, which are expressed to retire at a normal retirement age of 60 (subject to age discrimination).

Details of all payments to directors appear in the directors remuneration report.

In accordance with BP s Articles of Association, directors are granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. In respect of those liabilities for which directors may not be indemnified, the company maintained a directors and officers liability insurance policy throughout 2009. During the year, a review of the terms and scope of the policy was undertaken. The policy has been renewed for 2010. Although their defence costs may be met, neither the company s indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly. UK company law permits the company to advance costs to directors for their defence in investigations or legal actions.

Tenure and director elections

BP does not place a term limit on a director s service as the board considers this unnecessary in light of the company s long-established practice of proposing all directors for annual re-election by shareholders. The chairman and the nomination committee keep the tenure of the directors under review as part of the wider consideration of board skills and balance.

New board members are subject to election by shareholders at the first AGM following their appointment, with all existing directors standing for re-election each year. The notice of meeting contains a biography of each of the directors and a description of the skills and experience which the company feels is relevant to shareholders in taking an informed decision on their election.

Board independence

Non-executive directors are required to be independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement. The board has determined that non-executive directors who served during 2009 fulfilled this requirement and were independent. Upon appointment as chairman, the board was satisfied that I met the criteria of independence outlined above in the principles and in the UK Combined Code.

The board is also satisfied that there is no compromise to the independence or conflicts of interest of those directors who serve together as directors on the boards of outside entities or who have other appointments in outside entities. These issues are considered on a regular basis at board meetings.

Serving as a director

Induction and board learning

All directors receive a full induction programme when they join the board, including a core element covering BP s system of governance, the legal duties of directors of a listed company and the regulatory systems in the UK and US. The programme for non-executive directors has wider content which covers the business of the group and is tailored according to a director s own interests and needs and takes into account the tasks of the committees on which they will serve. Non-executive directors will receive presentations from senior management, have in-depth briefings on the company s strategy, plan and financial performance and be given the opportunity to visit BP s operations and meet employees at BP sites.

Prior to assuming the role of chairman, I received an extensive induction programme which covered:

Board matters, including directors duties, board issues and board committees.

The business environment for BP.

BP s core businesses: Exploration and Production, and Refining and Marketing.

Reviews of Alternative Energy and Group Technology.

Overviews of BP s functions including Finance, Safety and Operations, HR, Internal Audit, Legal, and Information Technology and Services.

BP s regional presence and key markets.

BP s strategic approach and financial framework.

BP s approach to risk management.

A review with the company s external auditor.

I had one-to-one meetings with each member of the board and undertook site visits to the Thunder Horse platform in the Gulf of Mexico and BP s fuels value chain in the western US. I attended meetings of the audit, remuneration, nomination and chairman s committees. I also met with a number of BP s largest shareholders. It was a lot of ground to cover and the process is still continuing.

As the chairman, I am responsible for ensuring that induction and training programmes are provided to all directors, and look at this provision on an individual basis. The company secretary assists in this and ensures that the programme to familiarize board members with BP s business is developed and updated in response to the needs of directors. During 2009, the board received briefings on biosciences, carbon policy and the economic outlook for the US, in addition to training at separate committees. Written updates were given on legal and regulatory issues.

All non-executive directors are required to participate in at least one site visit per year. During the year, site visits were made to the Projects and Operations Academies at the Massachusetts Institute of Technology, and to BP s fuels value chain in California, involving visits to a marine terminal, Carson Refinery, an inland distribution facility and a retail service station.

The effectiveness and relevance of the board s induction and training programmes are tested through their inclusion in the annual board evaluation. Feedback from the evaluation indicated that directors would welcome more deep-dive coverage of BP s business and more learning content on risk and the context for evaluating risk.

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Board performance and biographies

Board evaluation
BP undertakes an annual evaluation of the performance and effectiveness of the board, including the work of its committees. Evaluation of individual directors is undertaken by the chairman, with the chairman s committee evaluating the performance of the chairman.

By building on the results of the previous year s evaluation, the board tries to achieve a continuous cycle of evaluation, targeted actions arising from the review and performance improvement. Actions taken by the board during the year in response to the outcome of the 2008 review included greater focus on key areas of board learning, the undertaking of an investor audit to obtain feedback on BP s performance and expanded presentation of capital investment effectiveness.

For the 2009 evaluation, an external facilitator was engaged to provide me with an understanding of the dynamics and performance of the board as part of my induction as chairman.

Following a review of different providers, Boardroom Review was selected as external facilitator and it was determined that they had no other connection with the company. Boardroom Review undertook one-to-one interviews with each board member plus those who provide advice and support to the board and its committees. This was followed by observation of the board and each committee meeting in session. The evaluation report prepared by Boardroom Review was presented and discussed by the board in January 2010. The evaluation identified several areas of significant strength, including:

Strategic involvement: including the detailed and dynamic examination of information on the external environment and the impact and penetration of the work of the committees.

Board dynamics: examples cited include the breadth and depth of executive and non-executive experience and the open and transparent culture of the board.

Executive leadership: in particular the operational and performance focus of the executive team and their commitment to develop the board s understanding of future options, strategic partnerships and operational excellence.

Issues identified in the evaluation for the board to consider further included:

Strategy and risk: while the way in which the board dealt with strategy was seen to be a strength, the enhanced focus on risk meant the board was seeking ways to further improve its conversations on this.

The balance of formal and informal time: the time pressure on the board to balance workload coupled with the increasing expectations and responsibilities placed on board members. As a result, the board is considering how best to maximize its time together, including options such as scheduling more informal sessions outside board meetings whilst still encouraging board members to observe committee meetings of which they are not members in order to better understand the issues.

Board and committee tenure: with the retirement of several board members and the planned refreshment of the board, it was noted that board committees would be faced with turnover. Going forward, the board will examine ways of ensuring that committees do not face members retiring within the same timeframe and that there is appropriate cross membership between related committees.

Discussion of people and culture: with the ongoing process of change within the company, there is challenge for the board to maintain oversight on issues such as long-term retention, cultural values and practices across the group. The board is looking at how its committees can maintain a holistic view of these issues and how employee engagement, staff morale and retention strategy is monitored and influenced.

Time commitment and outside appointments

Letters of appointment to the BP board do not set out fixed time commitments for board duties as the company believes that the time required may change depending upon the demands of business. Membership of the board represents a significant time commitment and it is expected that directors will allocate sufficient time to the company to perform their responsibilities effectively. The nomination committee keeps this under review.

The company recognizes that executive directors may be invited to become non-executive directors of other companies. Such appointments can broaden their knowledge and experience, to the benefit of both the individual and the group. BP permits executive directors to take up one external board appointment, subject to the agreement of the chairman which is then reported to the BP board. Fees received for these external appointments may be retained by the executive director and are reported in the directors remuneration report. Non-executive directors may serve on a number of outside boards, provided they continue to demonstrate the requisite commitment to discharge their duties to BP effectively. The nomination committee keeps under review the nature of directors other interests to ensure that the efficacy of the board is not compromised and may make recommendations to the board if it concludes that a director s other commitments are inconsistent with those required by BP.

Board support and external advice

The chairman, assisted by the company secretary, ensures that board members receive timely and clear information on all matters relevant to the work and tasks of the board. Support to the board and its committees is provided through the company secretary s office, which reports to the chairman. The company secretary has no executive functions, with his appointment determined by the nomination committee and his remuneration determined by the remuneration committee.

Any BP director is entitled to obtain independent, professional advice relating to their own responsibilities and the affairs of BP; this advice will be at the expense of the company and facilitated through the company secretary s office. No BP directors sought such advice in 2009.

Board communication

Engagement with shareholders

The board represents the interests of all shareholders and seeks to act fairly between them. It is accountable to shareholders for the performance and activities of BP and engages in regular dialogue to understand their views and preferences.

The chairman, the group chief executive, other executive and non-executive directors and senior management, the company secretary s office, investor relations and other teams within BP engage with a range of shareholders on issues relating to the group. Presentations given by the group to the investment community are available to download from the Investors section of BP s website, as are speeches on topics of interest to shareholders made by the group chief executive and other senior management.

Peter Sutherland held a number of one-to-one meetings with investors over the course of the year to discuss issues relating to governance, succession, strategy and performance. The chair of the remuneration committee had meetings with institutional investors to discuss executive director remuneration.

A meeting was held in March 2009 for BP s largest shareholders with the chairman and the chairs of the board committees. Each chair gave a short presentation on his or her committee s work and the key challenges the committee faced in the year ahead, before opening the session up to questions. The meeting was aimed at providing our largest investors with an overview of the board s activities in advance of the AGM in April. Following positive feedback from both committee chairs and investors, a similar event will be held in 2010.

Board performance and biographies

I met a number of BP s largest shareholders in November to hear their views on the company and the activities of the board and its committees in advance of becoming chairman in January 2010.

Written and verbal feedback from shareholder meetings is shared with the wider board. During the year, the investor relations team engaged an external consultant to undertake an investor audit to solicit the views of major shareholders. The results of this audit were presented to the board in July. The board also receives regular reports on the company s share register, including explanations for movements in price and holdings of the company s ADRs and ordinary shares.

AGM

The AGM is an opportunity for BP s shareholders to ask questions and hear the resulting discussion about the company s performance and the directors stewardship of the company. Given the size and geographical distribution of the company s shareholder base BP recognizes that attendance may not be practical; therefore votes on all matters (except procedural issues) are taken by a poll at the AGM, meaning that every vote cast whether by proxy or in person at the meeting is counted.

The chairman and chairs of the board committees were present during the 2009 AGM and met shareholders on an informal basis after main business of the meeting. In 2009, voting levels at the AGM decreased slightly to 61%, compared with 63% in 2008. As in previous years the AGM was webcast, with the number of webcast downloads increasing over 2008 levels. The webcast, speeches and presentations given at the AGM are available on the BP website after the event, together with the outcome of voting on the resolutions.

Combined Code compliance

BP complied throughout 2009 with the provisions of the Combined Code on Corporate Governance, except in the following aspects:

A.4.4 Letters of appointment do not set out fixed time commitments since the schedule of board and committee meetings is subject to change according to the exigencies of the business. All directors are expected to demonstrate their commitment to the work of the board on an ongoing basis. This is reviewed by the nomination committee in recommending candidates for annual re-election.

B.2.2 The remuneration of the chairman is not set by the remuneration committee. Instead the chairman s remuneration is reviewed by the remuneration committee which makes a recommendation to the board as a whole for final approval, within the limits set by shareholders.

Internal control review

In discharging its responsibility for the company s system of internal control the board, through its governance principles, requires the group chief executive to operate with a comprehensive system of controls and internal audit to identify and manage the risks that are material to BP. The governance principles are reviewed periodically by the board and are consistent with the requirements of the Combined Code including principle C.2.

The board has an established process by which the effectiveness of this system of internal control is reviewed as required by provision C.2.1 of the Combined Code. This process enables the board and its committees to consider the system of internal controls being operated for managing significant risks, including social, environmental, safety, ethical and compliance risks, throughout the year. The process does not extend to joint ventures or associates.

As part of this process, the board and the audit and safety, ethics and environment assurance committees requested, received and reviewed reports from executive management, including management of the business segments and functions, at their regular meetings.

In considering the system, the board noted that such a system is designed to manage, rather than eliminate, the risk of failure to achieve business objectives and can only provide reasonable, and not absolute, assurance against material misstatement or loss.

During the year, the board through its committees regularly reviewed with the general auditor and executive management processes whereby risks are identified, evaluated and managed. These processes were in place for the year under review, remain current at the date of this report and accord with the guidance on the Combined Code provided by the Financial Reporting Council. In November, the board considered the group s significant risks within the context of the annual plan presented by the group chief executive.

A joint meeting of the audit and safety, ethics and environment assurance committees in January 2010 reviewed reports from the general auditor as part of the board s annual review of the system of internal control. The chairman of the board and the chairman of the remuneration committee also attended the meeting. The reports described the significant risks identified across the group within the categories of strategic, operational and compliance and control and considered the control environment which responds to such risks. The reports also highlighted the results of audit work conducted during the year and the remedial actions taken by management in response to significant failings and weaknesses identified.

During the year, these committees engaged with management, the general auditor and other monitoring and assurance providers (such as the group compliance and ethics officer and the external auditor) on a regular basis to monitor the management of risks. Significant incidents that occurred and management s response to them were considered by the appropriate committee and reported to the board.

In the board s view, the information it received was sufficient to enable it to review the effectiveness of the company s system of internal control in accordance with the Internal Control Revised Guidance for Directors in the Combined Code (Turnbull).

The board is satisfied that, where significant failings or weaknesses in internal controls were identified during the year, appropriate remedial actions were taken or are being taken.

On behalf of the board,

Carl-Henric Svanberg

Chairman

26 February 2010

Audit committee report

The report that follows outlines the principal responsibilities and method of operation of the audit committee, and highlights some of the specific activities it undertook during 2009.

The committee s main tasks include:

- Reviewing the effectiveness of BP s internal financial controls and its systems of internal control and risk management.

- Monitoring and obtaining assurance that the management and mitigation of significant risks of a financial nature facing BP are appropriately addressed.

- Monitoring the integrity of BP s financial statements and making recommendations to the board about their adoption and publication.

- Monitoring and reviewing the effectiveness of BP s internal audit function.

- Keeping under review the external auditor s independence and objectivity, and overseeing the effectiveness of the audit process.

- Making recommendations to the board on the appointment, re-appointment or removal of the external auditor and regarding the approval of their remuneration and terms of engagement.

- Monitoring the policy and its application on the engagement of the external auditor to supply non-audit services to BP.

- Reviewing the systems in place (including OpenTalk) to enable those who work for BP to raise, in confidence, any concerns about possible improprieties in matters of financial reporting or other financial issues and for those matters to be appropriately investigated.

Board performance and biographies

The full list of the tasks and requirements of the audit committee is set out in BP s board governance principles and can be found at *www.bp.com/governance*. The committee keeps these tasks under review to determine whether they remain fit for purpose. In 2009, the evaluation of the committee s work was conducted as an integral part of the external evaluation undertaken by the board. Following this evaluation, the board concluded that the committee had fulfilled its responsibilities as defined under the principles and that its tasks and requirements remained appropriate.

Committee structure

The audit committee comprises four independent non-executive directors selected to provide a wide range of financial, international and commercial expertise appropriate to fulfil the committee s duties. During 2009 the members, in addition to myself as chairman included George David, Erroll Davis, Jr and Douglas Flint. The secretary of the committee is David Pearl, deputy company secretary of BP.

The committee met 12 times in 2009, with an additional joint meeting between the audit committee and the safety, ethics and environment assurance committee (SEEAC) to review the general auditor s report on internal controls and risk management for the previous year. Each meeting was attended by the group chief financial officer, the deputy group chief financial officer, the group controller, the general auditor (head of internal audit) and the chief accounting officer. The lead partner of the external auditors (Ernst & Young) was also present. Other senior management are invited to attend when the business of the committee requires. During the year the committee held private sessions, usually at the end of each full meeting, without the presence of executive management. It also held separate sessions with only the external auditors present and only the general auditor present.

Carl-Henric Svanberg attended two meetings of the audit committee during the year as part of his board induction programme.

The board determined that Douglas Flint is the audit committee member with recent and relevant financial experience as defined by the Combined Code guidance.

The board also determined that Douglas Flint meets the independence criteria provisions of Rule 10A-3 of the US Securities Exchange Act of 1934 and that Mr Flint may be regarded as an audit committee financial expert as defined in Item 16A of the Annual Report on Form 20-F. Mr Flint is group finance director of HSBC Holdings plc and a former member of the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board.

After l retire from the BP board at the AGM in April 2010, it has been agreed that Douglas Flint will become chairman of the audit committee.

Attendance

	Audit committee meetings eligible to attend	Audit committee meetings attended
Sir Ian Prosser (chair)	13	13
E B Davis, Jr	13	11
D J Flint	13	12
G David	13	13

Information and external advice

The committee receives information and reports directly from accountable functional and business managers and from relevant external sources. BP s board governance principles are explicit that the board and its committees can access independent advice and counsel when needed on an unrestricted basis. Further support is provided by the company secretary s office and during 2009 external specialist legal and regulatory advice was provided to the audit committee in the normal course of carrying out its responsibilities by Sullivan & Cromwell LLP. In addition to the lead partner for Ernst & Young, other external audit staff also attended meetings where appropriate to a particular review of a business or function.

As part of its annual evaluation process, the audit committee looked at whether it has received sufficient and timely information to enable it to undertake its tasks effectively. It was concluded that the processes surrounding the reliability and timeliness of information was robust.

The board was kept updated and informed of the audit committee s activities and any issues that had arisen both through the committee minutes and also more immediately through verbal updates given by myself as committee chair as part of the board s regular agenda.

Training and visits

The composition of the committee was unchanged from the previous year, so training was focused on deepening knowledge rather than induction.

During the year the committee received briefings on financial reporting developments, governance changes affecting audit committees, new SEC regulations for oil and gas reserves accounting and tax reform.

In addition to the site visits made by the board as a whole, the audit committee visited BP s UK trading operations for an in-depth briefing on the fundamentals of oil and gas trading. This was supplemented by visits by myself and the secretary of the committee to BP s oil and gas trading operations in Houston and Chicago. These visits also provided an opportunity to meet staff of the independent monitor appointed for BP s US trading business. Two members of the committee also joined the SEEAC visit to BP s Projects and Operations Academies at MIT in March. I found that visit, and the one I made to the company s accounting, reporting and control course, provided valuable insight into training deep within the organization.

Committee activities in 2009

Board performance and biographies

Financial reporting

During the year, the committee reviewed the group s quarterly financial reports, the annual report and accounts, the annual review and the 20-F before recommending their publication to the board. The committee also discussed with management the critical accounting policies and judgements applied in the preparation of those financial reports. This included key assumptions regarding significant provisions, including those for decommissioning and environmental remediation and those used for impairment testing. *(See Financial statements Note 3 on page 122.)*

Monitoring business risk

The committee reviewed reports on the inherent risks within selected areas of BP s businesses and supporting functions. This together with the related controls and assurance processes is designed to manage and mitigate such risks. On top of reviewing the major business areas and functions within BP, this year specific focus was additionally given to Treasury activities, including debt and liquidity management, to information technology and to the group s oil and gas trading activities. The committee also reviewed risk management and investment strategy related to pensions and other post-retirement benefits, the management of taxation and litigation exposures and the management of BP s approach to insurance.

The work and scope of the executive-level Group Financial Risk Committee (which provides assurance to the executive on the management of BP s financial risk) was reported to the committee during the year by the chief financial officer.

Internal control and audit

The committee holds an annual joint meeting at the start of each year with the safety, ethics and environment assurance committee to review the general auditor s report on internal controls and risk management for the previous year. This provides important input into the board s review of the company s system of internal control.

The committee s agenda includes standing items addressing internal control and these included in 2009 the quarterly internal audit findings report and the annual assessment of BP s enterprise level controls.

Further detail on risk management and internal control in BP is outlined in the governance section of this board performance report above.

External auditors

The committee held two private meetings during the year with the external auditors. These provided additional opportunity for open dialogue and feedback from both the committee and the auditors without the presence of BP management. At these meetings, topics covered included the quality of interaction with executive management, the strength of the financial team and the effectiveness of the internal audit function. I also meet on my own with the external auditors prior to each audit committee to discuss the forthcoming agenda.

The committee undertakes regular reviews of the performance, effectiveness and viability of the external auditors. As part of its 2009 review, senior partners at Ernst & Young who were independent of the audit team responsible for BP undertook an evaluation process, which involved 22 face-to-face interviews with those BP board members and senior management who have key interactions with the external auditors. In addition, there was a web-based survey of 185 people representing a cross section of BP s global finance organization, covering both group reporting and statutory locations. The results of the interviews and surveys were presented to the committee by the independent senior partners in July and the auditors were asked to develop an action plan to address a small number of areas identified for improvement.

The external auditor followed up these findings with a report to the committee in November which outlined its responses to these areas. The external auditors will perform an assessment of service quality in 2010 to review the progress against the development areas outlined in the feedback.

Fees paid to the external auditor for the year (*see Financial statements Note 14 on page 134*) were $54 million, of which 15% was for non-audit work. The fees and services provided by Ernst & Young for both audit and non-audit work have decreased in comparison to previous years reflecting a joint approach to raising efficiency in audit processes as well as a reduction in tax services and services related to corporate finance transactions. All non-audit work is subject to the committee s advance approval policy and is monitored on a quarterly basis.

The audit committee has considered the proposed fee structure and audit engagement terms for 2010 and has recommended to the board that the reappointment of the external auditors be proposed to shareholders at the 2010 AGM.

Internal audit

The general auditor attends all committee meetings but also meets regularly on a one-to-one basis with myself as committee chairman. In July the general auditor met privately with the committee without the presence of executive management or the external auditors. In reviewing the effectiveness and quality of the internal audit, the committee also sought input from external auditors.

The committee receives a quarterly update on the progress of internal audit against its schedule of audits, is notified of their key findings and tracks any material actions that are overdue or have been rescheduled. The proposed internal audit work programme for the year was agreed by the committee in January. The committee was satisfied that it appropriately responded to the key risks facing the company and that the function had sufficient staff and resources to complete its work.

Other activities

The committee receives quarterly reports from the group compliance and ethics function which examine areas of potential non-compliance with the company s Code of Conduct and remedial actions that are being undertaken. The committee also receives an annual certification report which is signed by the group chief executive. The committee reviews quarterly reports on financial issues and concerns that have been raised through the group-wide employee concerns programme, OpenTalk and quarterly updates from internal audit on instances of actual or potential fraud.

Committee evaluation

The committee conducts an annual review of its performance and effectiveness. For 2009, this review was facilitated externally as part of the wider review of the board and its committees. The external facilitator undertook one-to-one interviews with each committee member, plus those who provide support to the committee and the external auditor. The review concluded that the audit committee was effective in carrying out its duties.

On behalf of the audit committee,

Sir Ian Prosser

Audit committee chairman

Board performance and biographies

Safety, ethics and environment assurance committee report

This report describes the role of the safety, ethics and environment assurance committee (SEEAC) and notes particular activities undertaken in 2009.

The role of the SEEAC requires us to look at the processes adopted by the executive management to identify and mitigate significant non-financial risks and receive assurance that they are appropriate in design and effective in implementation. Following the tragic incident at the Texas City refinery in 2005 the committee has observed a number of key developments, including: the establishment of a safety & operations (S&O) function with the highest calibre of staff; development of a group-wide operating management system (OMS) which is being progressively adopted by all operating sites; the establishment of training programmes in conjunction with MIT that are teaching project management and operational excellence; the dissemination of standard engineering practices throughout the group; and the formation of a highly experienced S&O audit team formed to assess the safety and efficiency of operations and recommend improvements. Throughout this time the group chief executive has made safety the number one priority. The committee s focus in S&O will now be to monitor how these advances are interpreted into the culture of day-to-day operations.

As in all years the committee has not focused solely on S&O. Our main tasks include:

Monitoring and obtaining assurance that the management or mitigation of significant BP risks of a non-financial nature is appropriately addressed.

Reviewing material to be placed before shareholders which address BP s environmental, safety and ethical performance and making recommendations to the board about their adoption and publication.

Reviewing BP s internal control systems as they relate to non-financial risk.

Reviewing reports on the group s compliance with its code of conduct and on the employee concerns programme (OpenTalk) as it relates to non-financial issues.

The full list of the tasks and requirements of the SEEAC are set out in BP s board governance principles, at *www.bp.com/governance*. The committee reviews its tasks and processes on a regular basis and seeks to learn from the challenges and issues of the previous year when setting its future agenda. Following the committee evaluation in 2009, which was an integral part of the external evaluation undertaken by the board, it was concluded that the SEEAC s tasks and requirements remained appropriate.

Committee structure

The SEEAC comprises four non-executive directors. Sir Tom McKillop left the committee when he retired from the board in April. Erroll Davis, Jr joined the SEEAC in May 2009 and will continue until his retirement in April 2010. Paul Anderson joined in February 2010. Both bring broad experience of the international energy industry. The committee membership is completed by Antony Burgmans, Cynthia Carroll and myself as chairman. Support is provided by the committee secretary, David Pearl, BP s deputy company secretary.

In addition to its non-executive members, the committee invites the lead partner of the external auditors, the BP general auditor (head of internal audit) and the group head of safety and operations to attend each meeting. Meetings are also attended by relevant senior executive managers. Tony Hayward was the principal executive liaison with the committee in 2009 and led the management reporting at all seven meetings of the SEEAC. The chief executives of Refining and Marketing, and Exploration and Production, Iain Conn and Andy Inglis, attended to report on topics specific to their businesses. As outlined in the report of the audit committee, one of SEEAC s meetings each year is held jointly with the audit committee to review BP s system of internal control and discuss the forward programme of the internal audit function.

The committee holds private sessions without the presence of executive management at the end of each meeting. This provides an opportunity to reflect on the effectiveness of each meeting and confirm actions to be pursued. Updating the wider board on the committee s activities and key issues is achieved through the circulation of minutes and through the verbal reports I provide as committee chairman to the board meetings.

Attendance

	SEEAC meetings eligible to attend	SEEAC meetings attended
Sir William Castell (chair)	7	7
A Burgmans	7	7
C B Carroll	7	5
E B Davis, Jr	4	3
Sir Tom McKillop	3	3

Information and external advice

SEEAC receives information from external and internal sources, including directly from the business segments and supporting functions such as group compliance and ethics, safety and operations and internal audit. During 2009 the committee s principal external input has been provided by Duane Wilson, the independent expert (*see the Independent expert section on the following page*). SEEAC can access any other independent advice and counsel if it requires, on an unrestricted basis.

Training and visits

The committee participated in the board s visit to the US west coast fuels value chain in September which enabled members to discuss safety, operational integrity and environmental matters first hand at a marine terminal, a refinery, an inland distribution terminal and a retail site.

The committee also visited the Projects and Operations Academies at MIT (described in the board report above), and participated in working sessions with course participants. In October the committee secretary and I visited the company s international centre for business and technology at Sunbury. We were briefed by the group head of engineering and group head of operations and their teams on OMS and the standard operating and engineering practices applied within the businesses.

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Board performance and biographies

Committee activities in 2009

Safety and operations

The committee received regular reports from the group operations risk committee (GORC) including data on company-wide safety and operational integrity performance, and was briefed on significant compliance issues including those arising with OSHA and other US regulatory agencies. We continued to monitor progress made in developing robust leading and lagging indicators in process safety. Other topics covered by the GORC and reviewed with the committee included improving corporate learning from safety incidents, strengthening the group-wide safety culture, and capability training programmes across the company. The committee also received a detailed briefing on the work of the safety and operations audit function.

North Sea helicopter incident

Following the tragic accident in April when a helicopter operated by Bond Offshore Helicopters carrying BP sub-contractors came down in the North Sea, Andy Inglis reviewed with the committee BP s response and the information emerging in interim reports from the UK Air Accident Investigation Branch (AAIB). Although the AAIB is yet to publish its final report, it is our understanding that the accident was caused by a gearbox failure. The impact of such an incident was deeply felt by the committee.

Independent expert

The committee spent considerable time with Mr Duane Wilson who was appointed in 2007 by the board as an independent expert to provide an objective assessment of BP s progress in implementing the recommendations of the BP US Refineries Independent Safety Review Panel (aimed at improving process safety performance at BP s five US refineries). Mr Wilson, who was previously a member of the panel and is independently funded through the company secretary s office, reported to us at five of our meetings. The committee was advised of evident progress against defined programmes to improve process safety performance at our US refineries. However it was also recognized that the journey requires investment not only in engineering but in sustaining cultural change and this will take many years to complete.

Mr Wilson s updates to the committee reflected the workplan which we agree with him annually and the outcomes of his visits to BP s
US refining sites. In March 2009, he published his second annual report which assessed BP s progress against the 10 panel recommendations. Mr Wilson concluded that good progress was being made, in particular that BP s tone at the top was reinforcing valuable positive messages on the importance of process safety, that the panel s recommendations had become embedded in the planning and resource allocation processes at all US refineries and that BP s Safety and Operations audit programme had matured into a comprehensive, high-quality programme. Areas where Mr Wilson believed more attention was warranted included further reduction in overtime, for the small percentage of individuals where this practice remained, in order to reduce the potential for fatigue, improvements to the investigation reports associated with incident investigations and development of comprehensive plans for safety instrumented systems (SIS) for the refineries in the US.

Mr Wilson s report was made available on BP s website.

Regional and functional reports

In the past year we have reviewed the company s approach to corporate social responsibility by taking BP s operations in Azerbaijan as a case study.

With BP operating one of the largest tanker fleets in the world we have sought and received assurance from its chief executive regarding fleet integrity and operating standards.

During 2009 we also reviewed reports on the identification and management of the group s security risks and the progress made in HSE at TNK-BP.

Internal audit and compliance and ethics

The committee received and discussed quarterly reports from the group compliance and ethics officer. Each year we review compliance with the company s code of conduct and the attention devoted to enforcing a standard of acceptable behaviour on a global basis. The group chief executive s own certification is provided to the committee. The compliance and ethics officer also reports to the committee on the operation of the employee concerns programme OpenTalk and the work of the US ombudsman. We are looking for further improvement in OpenTalk to be made in the coming year.

We also reviewed reports from internal audit addressing the programme of audits undertaken throughout the year, key audit findings and management s responses. These findings help focus our agendas to areas that require more attention. The committee was also briefed on the enhanced co-ordination between internal audit and other audit functions in the group, including Safety and Operations.

Other topics

During the year the committee was regularly updated on the company s plans in response to a potential pandemic and in May received a report on health risk management in the workplace. In October the committee reviewed risk evaluation and mitigation related to potential loss of containment in Refining and Marketing s logistics operations.

The committee believes, given the scale and diversity of this company and recognizing that it operates primarily in hydrocarbon businesses, that it receives information in sufficient depth to provide overall assurance of the management s commitment to achieve world class levels of safe, reliable and compliant operations.

On behalf of the safety, ethics and environment assurance committee,

Sir William Castell

SEEAC chairman

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Board performance and biographies

Remuneration committee report

Structure of the committee

Members of the remuneration committee during the year were Dr DeAnne Julius (chairman) and Sir Ian Prosser. Sir Tom McKillop stepped down from the committee when he retired from the board in April 2009 and Erroll Davis, Jr left the committee at the end of April 2009. Antony Burgmans and George David joined the committee in May 2009. The chairman of the board attends meetings of the committee and Carl-Henric Svanberg attended meetings prior to becoming chairman on 1 January 2010.

Attendance

The committee met eight times during 2009:

	Remuneration committee meetings eligible to attend	Remuneration committee meetings attended
Dr D S Julius (Chair)	8	8
A Burgmans	6	5
G David	6	6
E B Davis, Jr	2	2
Sir Tom McKillop	2	2
Sir Ian Prosser	8	8

Role and authority of the committee

The committee determines on behalf of the board the terms of engagement and remuneration of the group chief executive and executive directors and reports on these to shareholders. It also makes recommendations to the board regarding the chairman s remuneration. The committee is independently advised.

Further details on the committee s role, authority and activities during the year are set out in the directors remuneration report, which is the subject of a vote by shareholders at the 2010 AGM.

On behalf of the remuneration committee,

Dr DeAnne Julius

Remuneration committee chairman

Nomination committee report

This has been a very active year for the committee which has met 15 times.

The main tasks of the committee are:

- Identifying, evaluating and recommending candidates for the appointment or re-appointment as directors.
- Identifying, evaluating and recommending candidates for appointment as company secretary.
- Keeping under review the mix of knowledge, skills and experience of the board to ensure an orderly succession of directors.
- Reviewing the outside directorships and broader commitments of the non-executive directors.

Committee structure

The committee is comprised of the chairman and the chairs of the SEEAC, audit and remuneration committees. During the year, Peter Sutherland, Sir William Castell, Sir Ian Prosser and Dr DeAnne Julius were members. After his appointment on 1 September, Carl-Henric Svanberg has attended meetings of the committee. Dr Hayward has also attended certain meetings of the committee during the year.

Attendance

	Nomination committee meetings eligible to attend	Nomination committee meetings attended
P D Sutherland	15	12
Sir William Castell	15	14
Sir Ian Prosser	15	15
D S Julius	15	14

The work of the committee during the year has been focused on two areas:

1. The completion of the process for the selection of a successor to Peter Sutherland as chairman.
   Sir Ian Prosser chaired the committee in this activity. After an intensive process involving two external search consultants, Carl-Henric Svanberg was selected as the next chairman in June 2009. He became a non-executive director on 1 September 2009 and took the chair on 1 January 2010.

2. The continuing refreshment of the board.

   During the year the committee has reviewed the skills needed for the board against the competences and experience of the current directors. Sir Tom McKillop retired from the board in April and Sir Ian Prosser and Erroll Davis, Jr will retire at the next AGM. In the second half of the year, the focus has been on refreshing the board and identifying a number of candidates available to join the board in the short and medium term. Two non-executive director appointments were made in early 2010 following this process: Paul Anderson in February and Ian Davis in March to take effect in April. This work will continue as Dr Julius retires in 2011.

On behalf of the nomination committee,

Carl-Henric Svanberg

Chairman

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Board performance and biographies

Chairman s committee report

The committee met five times in 2009.

Committee structure

The chairman s committee consists of the chairman and all the non-executive directors.

Attendance

	Chairman's committee meetings eligible to attend	Chairman's committee meetings attended
P D Sutherland	5	3
Sir Ian Prosser	5	5
A Burgmans	5	5
C B Carroll	5	5
Sir William Castell	5	4
G David	5	5
E B Davis, Jr	5	5
D J Flint	5	5
D S Julius	5	5
Sir Tom McKillop	1	1
C-H Svanberg	2	2

The main tasks of the committee are:

- Evaluating the performance and effectiveness of the group chief executive.
- Reviewing the structure and effectiveness of the business organization of BP.
- Reviewing the systems for senior executive development and determining the succession plan for the group chief executive, executive directors and other senior members of executive management.
- Determining any other matter which is appropriate to be considered by all of the non-executive directors.
- Opining on any matter referred to it by the chairman of any committee comprised solely of non-executive directors.

Committee activities

During the year, the committee reviewed:

- The performance of the group chief executive and with him, the performance of the other executive directors.
- The performance of the chairman.
- The succession plan for the executive team and any development issues.

Dr Hayward attended a number of meetings of the committee and considered with the committee his response to the strategic and operational challenges facing the group and their implication for the evaluation of the senior management team. Corporate culture and tone from the top also remain an area of active discussion.

On behalf of the chairman s committee,

Carl-Henric Svanberg

Chairman

Directors interests

Current directors	At 31 Dec 2009	At 1 Jan 2009	Change from 31 Dec 2009 to 18 Feb 2010
A Burgmans	10,156	10,000	
C B Carroll	10,500[b]		
Sir William Castell	82,500	82,500	
I C Conn	293,216[a]	240,789[a]	56,604
G David	39,000[b]	9,000[b]	
E B Davis, Jr	76,497[b]	73,185[b]	
D J Flint	15,000	15,000	
Dr B E Grote	1,291,643[c]	1,214,330[c]	59,886
Dr A B Hayward	535,383	488,459	87,424
A G Inglis	259,163[d]	226,175[d]	49,476
Dr D S Julius	15,000	15,000	
Sir Ian Prosser	16,301	16,301	

Directors leaving the board	At resignation/retirement	At 1 Jan 2009
Sir Tom McKillop	20,000[e]	20,000
P D Sutherland	30,906[f]	30,906

Directors joining the board	At 31 Dec 2009	On appointment	Change from 31 Dec 2009 to 18 Feb 2010
P Anderson		6,000[b g]	
R W Dudley	276,846	269,746[b h]	
C-H Svanberg		[i]	750,000

[a]Includes 47,320 shares held as ADSs at 31 December 2009 and 44,158 shares held as ADSs at 1 January 2009.

[b]Held as ADSs.

[c]Held as ADSs, except for 94 shares held as ordinary shares.

[d]Includes 34,962 shares held as ADSs.

[e]On retirement at 16 April 2009.

[f]On retirement at 31 December 2009.

[g]On appointment at 1 February 2010.

[h]On appointment at 6 April 2009.

[i]On appointment at 1 September 2009.

The above figures indicate and include all the beneficial and non-beneficial interests of each director of the company in shares of the company (or calculated equivalents) that have been disclosed to the company under the Disclosure and Transparency Rules as at the applicable dates.
Executive directors are also deemed to have an interest in such shares of the company held from time to time by the BP Employee Share Ownership Plan (No. 2) to facilitate the operation of the company s option schemes.

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

Directors
remuneration report

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Directors remuneration report

Part 1 Summary

In a volatile year for the world economy, the BP executive team produced excellent results. While salaries were frozen for all directors in 2009, the variable performance-related pay reflected the impressive achievements of the year and the turnaround of performance over the past three years. The details of executive director remuneration are set out in the table on the opposite page.

The remuneration committee sets the measures and targets for the annual bonus element of variable pay at the beginning of the year, based on the strategy and annual plan accepted by the board. The strategy is built around safety, people and performance. The measures included key safety measures (15% of bonus), staff numbers and survey results to reflect the people priorities (15%) and a set of financial and operational targets to measure performance (70%). Nearly all targets were exceeded, some substantially, with particularly strong performance on cost reduction, exploration success, production start-ups and refining performance. This overall excellent performance was also reflected in the market, where BP shareholders recorded the highest total shareholder return (TSR) of all the oil majors for the year.

The other element of variable pay is awarded in shares based on BP s performance over three years, compared with the other oil majors. Following the process approved by shareholders in the Executive Directors Incentive Plan (EDIP), the committee first reviews the three-year TSR of BP compared with its peers and then considers a set of underlying business metrics, again in comparison with peers. When there is a difference between the two comparisons, the committee decides which level of vesting best represents BP s relative three-year performance. This year the TSR result was tightly clustered and sensitive to calculation methodology. For example, based on a three-month averaging of endpoints, BP came fourth whereas on a one-month averaging it came second. On underlying metrics, BP ranked first on four of the six reviewed (production growth, earnings per share growth, change in return on average capital employed and free cash flow) and second or third on the others (Refining and Marketing earnings per barrel
and net income growth). Following the process set out in the EDIP, the committee judged BP to be tied for third place and thus shared the vesting outcome for third and fourth place to result in a vesting of 17.5% of the maximum award.

During the year the committee conducted a full review of BP s remuneration policy, and particularly the EDIP, which is being put before shareholders for renewal this year. We consulted with a number of our shareholders, reviewed the actual experience with applying EDIP rules over the past five years and considered recent developments in the marketplace. Overall we concluded that the basic structure of the EDIP remains appropriate, but that some rebalancing of elements is warranted. The key change we propose is to require a portion of the annual bonus to be deferred, paid in shares and matched after three years subject to an assessment of safety and environmental sustainability over the three-year period. This change would place more focus on the long term, highlight the importance of safety and build a larger equity stake for executives that we believe aligns their interests well with shareholders. To balance this additional bonus element, we propose to reduce the maximum award of performance shares in the renewed EDIP so as to maintain the current quantum of total remuneration. These changes are summarized in the table below.

It has been an excellent year for BP and its shareholders. In determining annual and long-term awards, the committee has recognized the very real achievements of the executive team. For the future, we believe our revised EDIP provides a sound framework with which to competitively reward our top executives for continued success in this long-term business.

Dr DeAnne S Julius
Chairman, Remuneration Committee
26 February 2010

Summary of future remuneration components

Salary	Normally reviewed mid-year (no increases in 2009). Current salaries: Dr Hayward £1,045,000, Mr Conn £690,000, Mr Dudley $1,000,000, Dr Grote $1,380,000, Mr Inglis £690,000.
Bonus	On-target bonus of 150% of salary and maximum of 225% of salary based on performance relative to targets set at start of year relating to financial and operational metrics.
Deferred bonus and match	One-third of actual bonus awarded as shares with three-year deferral, with ability to voluntarily defer an additional one-third. All deferred shares matched one-for-one, both subject to an assessment of safety and environmental performance over the three-year period.
Performance shares	Following EDIP renewal, award of shares of up to 5.5 times salary for group chief executive, 4.75 times for the chief executive of Exploration and Production, and 4 times for other executive directors. Vesting after three years based on performance relative to other oil majors. Three-year retention period after vesting before release of shares.
Pension	Final salary scheme appropriate to home country of executive.

Directors remuneration report

Summary of remuneration of executive directors in 2009[a]

	Annual remuneration								Long-term remu		
									Share element		
									2006-2008 plan (vested in Feb 2009)		2007-200 (vested
	Salary[b] (thousand)		Annual performance bonus (thousand)		Non-cash benefits and other emoluments (thousand)		Total (thousand)		Actual[c] shares vested	Value[d] (thousand)	Actual[c] shares vested
	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**			
Dr A B Hayward	£998	**£1,045**	£1,496	**£2,090**	£15	**£23**	£2,509	**£3,158**	66,136	£336	147,985
I C Conn	£670	**£690**	£871	**£1,104**	£45	**£46**	£1,586	**£1,840**	66,136	£336	95,697
R W Dudley[g h]	n/a	**$750**	n/a	**$1,125**	n/a	**$304**[i]	n/a	**$2,179**	n/a	n/a	n/a
Dr B E Grote[g]	$1,340	**$1,380**	$1,742	**$2,070**	$8	**$8**	$3,090	**$3,458**	80,231	$603	101,502[e]
A G Inglis	£670	**£690**	£1,173	**£1,311**	£212	**£216**[j i]	£2,055	**£2,217**	54,994	£279	83,859

Amounts shown are in the currency received by executive directors. Annual bonuses are shown in the year they were earned.

[a] This information has been subject to audit.

[b] Figures show the total salary received during the calendar year. The last salary increase was in July 2008.

[c] Includes shares representing reinvested dividends received on the shares that vested at the end of the performance period.

[d] Based on market price on vesting date (£5.08 per share/$45.13 per ADS).

[e] Based on market price on vesting date (£5.76 per share/$55.17 per ADS).

[f] Maximum potential shares that could vest at the end of the three-year period depending on performance.

[g] Dr Grote and Mr Dudley hold shares in the form of ADSs. The above number reflects calculated equivalent in ordinary shares.

[h] Reflects remuneration received by Mr Dudley since appointment as executive director on 6 April 2009.

[i] This amount includes costs of London accommodation and any tax liability thereon.

[j] In addition to this amount, under a tax equalization arrangement, BP discharged a US tax liability arising from the participation by Mr Inglis in the UK pension scheme amounting to $90,314.

This graph shows the growth in value of a hypothetical £100 holding in BP p.l.c. ordinary shares over five years, relative to the FTSE 100 Index (of which the company is a constituent). The values of the hypothetical £100 holdings at the end of the five-year period were £141.75 and £134.58 respectively.

Remuneration of non-executive directors in 2009[a]

		£ thousand
	2008	**2009**
P D Sutherland	600	**600**
A Burgmans	90	**93**
Sir William Castell	108	**115**
C B Carroll	93	**90**
G David[b]	100	**118**
E B Davis, Jr	105	**105**
D J Flint	90	**85**
Dr D S Julius	110	**105**
Sir Ian Prosser	170	**165**
C-H Svanberg[c]	n/a	**30**
Directors leaving the board in 2009		
Sir Tom McKillop	95	**33**

[a] This information has been subject to audit.

[b] Also received £4,166 for serving as a member of BP s technology advisory committee.

[c] Appointed on 1 September 2009.

While fees were held at 2008 levels, in 2009 actual fees paid to non-executive directors were affected by changes in committee membership and the number of transatlantic meetings for which an attendance allowance was paid.

In 2009 the chairman reviewed non-executive director remuneration taking into account the review completed in 2008. The chairman made a recommendation to the board (which was agreed) to maintain the 2008 structure until a further review in 2010.

Directors remuneration report

Part 2 Executive directors remuneration
2009 remuneration

Salary

Executive directors have had no salary increases since July 2008, with the exception of Mr Dudley who was appointed to the board in April 2009. Dr Hayward s salary remains £1,045,000, Mr Conn s £690,000, Mr Dudley s $1,000,000, Dr Grote s $1,380,000, and Mr Inglis s £690,000.

Annual bonus

The annual bonus awards for 2009 reflect the excellent performance achieved across the business and are set out in the table on page 79.

Performance measures and targets were set at the beginning of the year based on the group s annual plan. Group results formed the basis for Dr Hayward s, Mr Dudley s and Dr Grote s annual bonus and were weighted 70% on financial and operating results (including profit, cash flow, cash costs, production, reserves replacement, Refining and Marketing profitability, refining availability, and installed wind capacity), 15% on safety (both metrics and progress on plans), and 15% on people (including organizational changes and employee attitudes). Mr Conn s and Mr Inglis s annual bonuses were based 50% on the group results as above, and 50% on their respective business unit results (also a mix of financial, operating, safety and people measures). The target level of bonus for executive directors was 120% of salary with committee judgement to award up to 150% for exceeding targets and above that level to recognize exceptional performance.

Targets were exceeded on virtually all key measures during 2009, a number by a substantial margin and resulting in bonuses averaging 170% of salary.

All key safety and operating metrics (including days away from work case frequency (DAFWCF), recordable injury frequency (RIF), oil spills, loss of primary containment, and process safety high potential incidents) showed good results and significant improvements in all cases from 2008. Implementation of the operating management system (OMS) progressed ahead of plan and is now successfully installed at 70 operating entities including all major downstream sites. People metrics were also exceeded. Major organizational restructuring was completed including reducing the number of group leaders and senior level leaders in excess of plan. The employee survey results showed significant improvement in key aspects such as safety and compliance and performance culture, as well as overall employee satisfaction.

Exceptional results were achieved on financial and operating measures. Replacement cost profit was some $5 billion above plan after adjusting for the oil price and other environmental factors. Cash costs were reduced substantially. Production increased by more than 4% while unit production costs reduced by 12%. The reserves replacement ratio was 129%, continuing an industry-leading performance. Refining and Marketing cash costs were reduced by 15%, and refining availability increased to 94%. Refining and Marketing profitability exceeded plan after adjusting for a dramatically weaker industry environment. Exploration and Production achieved major project start-ups in the Gulf of Mexico, Indonesia and Trinidad & Tobago. Exploration successes included the Tiber discovery in the Gulf of Mexico and new access for future growth was secured in Iraq, Indonesia and Jordan as well as new acreage in the Gulf of Mexico.

The excellent results achieved during 2009 reflect the strong leadership of the executive team and their continuing focus on safety, people and performance.

2007-2009 share element

This momentum of improvement is also apparent over the three-year performance period covered by the 2007-2009 share element under the EDIP. Performance for the share element is assessed relative to the other oil majors ExxonMobil, Shell, Total and Chevron. The committee follows the assessment process approved by shareholders in determining the vesting of shares that had been awarded at the start of 2007. It first compares the total shareholder return (TSR) of each of the majors and then reviews underlying performance metrics across the same group. Given the small peer group, similarity of their businesses, and general imperfections in measurement, there will be occasions when results of some or all of the companies are tightly clustered. In such circumstances, a small difference in TSR performance or calculation methodology could produce a large, and inappropriate, difference in vesting level. To counter this the committee has the obligation to review both relative TSR and underlying performance to ensure a balanced judgement is made. Such was the case with regard to the 2007-2009 metrics.

The TSR result was tightly clustered for 2007-2009 with BP coming fourth based on our established methodology but very close to third place. As required by the plan, the committee reviewed a number of financial and operating metrics to assess relative underlying performance. These included the average change over the three years of EPS, ROACE, free cash flow, net income, production growth and Refining and Marketing profitability. The review of underlying performance showed BP in a strong relative position. BP came first on change in EPS growth, ROACE, free cash flow and production, on adjusted net income BP ranked second and on Refining and Marketing profitability it came third. Based on the full review and combining both the TSR and underlying analysis, the committee judged BP to be tied for third place and thus shared the vesting outcome for third and fourth place (35% and 0% respectively) as set out in the plan rules. The resulting 17.5% vesting for eligible participants is also shown in the table on page 79.

Remuneration policy review

During 2009 the committee carried out a comprehensive review of its remuneration policy for executive directors. The review covered all components of remuneration, both fixed and variable, short term and long term. It focused especially on the EDIP which provides the framework for long-term, variable pay. The current EDIP was approved by shareholders in 2005 and will expire in April 2010, when a renewal will be put to shareholder vote. As part of its review the committee met with key shareholders to assess the current pay structure and test areas for change.

The basic principles that guide remuneration policy for executive directors in BP formed the starting point for the review. These include:

A substantial portion of executive remuneration should be linked to success in implementing the company s business strategy to maximize long-term shareholder value.

Executives should develop and be required to hold a significant shareholding as this represents the best way to align their interests with those of shareholders.

The structure of pay should reflect the long-term nature of BP s business and the significance of safety and environmental risks.

Performance conditions for variable pay should be set independently by the committee at the outset of each year and assessed by the committee both quantitatively and qualitatively at the end of each performance period.

Performance assessment should take into account material changes in the market environment (predominantly oil prices) and BP s competitive position (primarily vis-à-vis other oil majors).

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Directors remuneration report

Salaries should be reviewed annually, in the context of the total quantum of pay, and taking into account both external market and internal company conditions.

The remuneration committee will actively seek to understand shareholder preferences and be as transparent as possible in explaining its remuneration policy and practices.

The committee s review concluded that the basic structure of fixed and variable pay remains appropriate. The EDIP gives the committee a range of tools, within an overall framework approved by shareholders, with which to construct remuneration packages that are tailored to the company s business objectives each year and are calibrated to achieve the desired linkage between performance and pay.

While the basic structure of the EDIP remains appropriate, the committee concluded that three of its features should be revised. First, with respect to the annual bonus, a new element should be added to require one-third of the bonus to be deferred for three years and paid in shares rather than cash. At the end of this three-year period, subject to an assessment of safety and environmental sustainability, the deferred bonus would be matched with additional shares on a one-for-one basis. Executives would also have the opportunity to defer an additional one-third of their annual bonus on this basis.

Second, with respect to the long-term performance share element, the maximum number of shares should be reduced to offset the more generous annual bonus and deferred element in the revised EDIP and thereby keep the total quantum of remuneration roughly constant.

Third, the current EDIP includes a provision for discretionary cash payments which has never been used. This provision will be omitted from the revised EDIP.

Detail of elements of remuneration

The majority of total remuneration is long term and varies with performance, with the largest elements share based, further aligning interests with shareholders.

Salary

The committee normally reviews salaries annually, taking into account other large Europe-based global companies as well as relevant US companies. These groups are each defined and analysed by the committee s independent remuneration advisers.

Annual bonus

The committee sets bonus targets and levels of eligibility each year for all executive directors. For the 2010 bonus, the committee has adjusted bonus levels and structure of payment, as part of the wider rebalancing of the remuneration mix.

The on-target bonus level for 2010 is 150% of salary with the maximum of 225% of salary. This was changed from the target for 2009 referred to earlier.

Group results will be determined based on six metrics comprising safety, people and four performance-related measures including:

Group replacement cost profits.

Cash costs.

Production and reserves replacement.

Refining and Marketing income per barrel.

Dr Hayward s and Mr Dudley s bonus will be based on group results.

Mr Conn, Dr Grote and Mr Inglis will have 70% of their bonus based on the above group results and 30% on the results of their respective business segments as measured by key performance metrics and milestones set out in the annual plan. For Exploration and Production, these include production costs and reserves replacement as well as safety and new opportunities. For Finance, they focus on specific business and cost targets. For Refining and Marketing, they include refining availability, earnings and cash costs, as well as safety and work simplification.

The committee will also review carefully the underlying performance of the group in light of company business plans and will look at competitors results, analysts reports and the views of the chairmen of other BP board committees when assessing results.

The committee can decide to reduce bonuses where this is warranted and, in exceptional circumstances, bonuses can be reduced to zero.

Deferred bonus

One-third of the annual bonus will be deferred into shares for three years and matched by the company on a one-for-one basis. Both deferred and matched shares will vest contingent on an assessment of safety and environmental sustainability over the three-year deferral period. If the committee assesses that there has been a material deterioration in safety and environmental metrics, or there have been major incidents revealing underlying weaknesses in safety and environmental management, then it may conclude that shares should vest in part, or not at all. In reaching its conclusion, the committee will obtain advice from the safety, ethics and environment assurance committee (SEEAC).

Executive directors may voluntarily defer a further one-third of their annual bonus into shares, which will be capable of vesting, and will qualify for matching, on the same basis as set out above.

Where shares vest, the executive director will receive additional shares representing the value of the reinvested dividends.

This structure of deferred bonuses, paid in shares, places increased focus on long-term alignment and reinforces the critical importance of maintaining high safety and environmental standards.

Performance shares

The share element of the EDIP has been a feature of the plan, with some modifications, since its inception in 2000. To reflect the introduction of the deferred matching element, the maximum number of shares that can be awarded will be reduced from 7.5 times salary to 5.5 times salary for the group chief executive and from 5.5 times salary to 4.75 times salary for the chief executive of Exploration and Production, and to four times salary for the other executive directors.

Performance shares will only vest to the extent that a performance condition is met, as described below. In addition, the committee will have an overriding discretion, in exceptional circumstances (relating to either the company or a particular participant) to reduce the number of shares that vest (or to provide that no shares vest).

The compulsory retention period will also be decided by the committee and will not normally be less than three years. Together with the performance period, this gives executive directors a six-year incentive structure, which is designed to ensure their interests are aligned with those of shareholders.

Where shares vest, the executive director will receive additional shares representing the value of the reinvested dividends.

The committee s policy, reflected in the EDIP, continues to be that each executive director builds a significant personal shareholding, with a target of shares equivalent in value to five times salary, within a reasonable time from appointment as an executive director.

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Directors remuneration report

Performance conditions
Performance conditions for the 2010-12 share element will continue the structure used in the 2009-2011 plan.

Vesting of shares will be based, as to one-third, on BP s TSR compared with other oil majors over a three-year period and as to two-thirds, on a balanced scorecard of underlying performance. BP s TSR performance will be compared with the other oil majors ExxonMobil, Shell, Total, ConocoPhillips and Chevron. This comparison group can be altered if circumstances change, for example, if there is significant consolidation or change in the industry. While this comparison group is narrow, it is used by both management and shareholders in assessing BP s comparative TSR performance.

The inclusion of relative TSR is an appropriate way of measuring performance for the purposes of a long-term incentive for executive directors as it reflects the creation of shareholder value while minimizing the impact of sector specific events such as the oil price. TSR is calculated as share price performance over the relevant period, assuming dividends are reinvested. All share prices are averaged over the three-month period before the beginning and end of the performance period. They are measured in US dollars.

The balanced scorecard will be assessed by the committee on three measures reflecting key priorities in BP s strategy, production growth, Refining and Marketing profitability and group underlying net income. Both production growth and Refining and Marketing profitability are key strategic objectives for the group and key drivers of value for shareholders. Group underlying net income acts as a holistic measure of success reflecting revenues, costs and complexity as well as safe and reliable operations. The three underlying measures will be averaged to form the balanced scorecard component.

All the above measures will be compared with the other oil majors to determine the overall vesting result. The methodology used will rank each of the five other majors on each of the measures. BP s performance will then be compared on an interpolated basis relative to the performance of the other five. Performance shares will vest at 100%, 70% and 35% for performance equivalent to first, second and third rank respectively and none for fourth or fifth place. For performance between second and third or first and second, the result will be interpolated based on BP s performance relative to the company ranked directly above and below it.

The committee considers that this combination of measures provides a good balance of external as well as internal metrics reflecting both shareholder value and operating priorities. As in previous years, the committee may exercise its discretion, in a reasonable and informed manner, to adjust vesting levels upwards or downwards if it concludes the quantitative approach does not reflect the true underlying health and performance of BP s business relative to its peers. It will explain any adjustments in the next directors remuneration report following the vesting, in line with its commitment to transparency.

In exceptional recruitment circumstances, the committee may award performance shares that are subject to a requirement of continued service over a specified period, rather than a corporate performance condition.

Pensions

Executive directors are eligible to participate in the appropriate pension schemes applying in their home countries. Details are set out in the table on page 83.

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

The rules of the BP Pension Scheme were amended in 2006 such that the normal retirement age is 65. Prior to 1 December 2006, scheme members could retire on or after age 60 without reduction. Special early retirement terms apply to pre-1 December 2006 service for members with long service as at 1 December 2006.

Pension benefits in excess of the individual lifetime allowance set by legislation are paid via an unapproved, unfunded pension arrangement provided directly by the company.

Although Mr Inglis is, like other UK directors, a member of the BP Pension Scheme, he is currently based in Houston, US. His participation in the BP Pension Scheme gives rise to a US tax liability. During 2009, the committee approved the discharge of this US tax liability under a tax equalization arrangement amounting to $90,314.

US directors

Dr Grote and Mr Dudley participate in the US BP Retirement Accumulation Plan (US plan) which features a cash balance formula. Pension benefits are provided through a combination of tax-qualified and non-qualified benefit restoration plans, consistent with US tax regulations as applicable.

The Supplemental Executive Retirement Benefit (supplemental plan) is a non-qualified top-up arrangement that became effective on 1 January 2002 for US employees above a specified salary level. The benefit formula is 1.3% of final average earnings, which comprise base salary and bonus in accordance with standard US practice (and as specified under the qualified arrangement), multiplied by years of service. There is an offset for benefits payable under all other BP qualified and non-qualified pension arrangements. This benefit is unfunded and therefore paid from corporate assets.

Dr Grote and Mr Dudley are eligible to participate under the supplemental plan. Their pension accrual for 2009, shown in the table below, includes the total amount that could become payable under all plans.

Other benefits

Executive directors are eligible to participate in regular employee benefit plans and in all-employee share saving schemes applying in their home countries. Benefits in kind are not pensionable. BP provides accommodation in London for both Mr Inglis and Mr Dudley.

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Directors remuneration report

Pensions[a]

						thousand
	Service at 31 Dec 2009	Accrued pension entitlement at 31 Dec 2009	Additional pension earned during the year ended 31 Dec 2009[b]	Transfer value of accrued benefit[c] at 31 Dec 2008 (A)	Transfer value of accrued benefit[c] at 31 Dec 2009 (B)	Amount of B-A less contributions made by the director in 2009
Dr A B Hayward (UK)	28 years	£584	£23	£8,045	£10,840	£2,743
I C Conn (UK)	24 years	£276	£12	£3,161	£4,508	£1,347
R W Dudley (US)[d]	30 years	$406	$106	$2,994	$4,353	$1,358
Dr B E Grote (US)	30 years	$1,011	$143	$11,220	$12,047	$827
A G Inglis (UK)	29 years	£337	£12	£4,399	£6,000	£1,601

[a]This information has been subject to audit.

[b]Additional pension earned during the year includes an inflation increase of 0.9% for UK directors and 0% for US directors.

[c]Transfer values have been calculated in accordance with guidance issued by the actuarial profession.

[d]Figures represent period after joining the board on 6 April 2009.

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Directors remuneration report

Performance share element of EDIP[a]

				Share element interests			Interests vested in 2009 and 2010		
				Potential maximum performance shares[b]					
	Performance period	Date of award of performance shares	Market price of each share at date of award of performance shares £	At 1 Jan 2009	Awarded 2009	At 31 Dec 2009	Number of ordinary shares vested[c]	Vesting date	Market price of each share at vesting £
Dr A B Hayward	2006-2008	16 Feb 2006	6.54	383,200			66,136	6 Feb 2009	5.08
	2007-2009	06 Mar 2007	5.12	706,311		706,311	147,985	3 Feb 2010	5.76
	2008-2010	13 Feb 2008	5.61	845,319		845,319			
	2009-2011	11 Feb 2009	5.10		1,182,540	1,182,540			
I C Conn	2006-2008	16 Feb 2006	6.54	383,200			66,136	6 Feb 2009	5.08
	2007-2009	06 Mar 2007	5.12	456,748		456,748	95,697	3 Feb 2010	5.76
	2008-2010	13 Feb 2008	5.61	578,376		578,376			
	2008-2011[d]	13 Feb 2008	5.61	133,452		133,452			
	2008-2013[d]	13 Feb 2008	5.61	133,452		133,452			
	2009-2011	11 Feb	5.10		780,816	780,816			

		2009							
R W Dudley[e]	2009-2011	6 May 2009	5.00		539,634	539,634			
Dr B E Grote[e]	2006-2008	16 Feb 2006	6.54	470,432			80,231	6 Feb 2009	5.08
	2007-2009	06 Mar 2007	5.12	491,640		491,640	101,502	3 Feb 2010	5.76
	2008-2010	13 Feb 2008	5.61	581,748		581,748			
	2009-2011	11 Feb 2009	5.10		992,928	992,928			
A G Inglis	2006-2008	27 Mar 2006	6.59	325,750			54,994	6 Feb 2009	5.08
	2007-2009	06 Mar 2007	5.12	400,243		400,243	83,859	3 Feb 2010	5.76
	2008-2010	13 Feb 2008	5.61	578,376		578,376			
	2008-2011[d]	13 Feb 2008	5.61	133,452		133,452			
	2008-2013[d]	13 Feb 2008	5.61	133,452		133,452			
	2009-2011	11 Feb 2009	5.10		780,816	780,816			
Former directors									
Dr D C Allen	2006-2008	16 Feb 2006	6.54	383,200			34,518	6 Feb 2009	5.08
	2007-2009	06 Mar 2007	5.12	456,748		456,748	47,848	3 Feb 2010	5.76

[a]This information is subject to audit.

[b]BP s performance is measured against the oil sector. For awards under the 2006-2008 through 2008-2010 plans, the performance condition is TSR measured against ExxonMobil, Shell, Total and Chevron. For awards under the 2009-2011 plan, performance conditions are measured 50% on TSR against ExxonMobil, Shell, Total, ConocoPhillips and Chevron and 50% on a balanced scorecard of underlying performance. Each performance period ends on 31 December of the third year.

[c]Represents awards of shares made at the end of the relevant performance period based on performance achieved under rules of the plan and includes reinvested dividends on the shares awarded.

[d]Restricted award under share element of EDIP. As reported in the 2007 directors remuneration report in February 2008, the committee awarded both Mr Inglis and Mr Conn restricted shares, as set out above. These one-off awards will vest on the third and fifth anniversary of the award, dependent on the remuneration committee being satisfied as to their personal performance at the date of vesting. Any unvested tranche will lapse in the event of cessation of employment with the company.

[e]Dr Grote and Mr Dudley receive awards in the form of ADSs. The above numbers reflect calculated equivalents in ordinary shares.

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Directors remuneration report

Share options[a]

	Option type	At 1 Jan 2009	Granted	Exercised	At 31 Dec 2009	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
Dr A B Hayward	SAYE	3,220			3,220	£ 5.00		01 Sep 2011	29 Feb 2012
	EXEC	34,000			34,000	£ 5.99		15 May 2003	15 May 2010
	EXEC	77,400			77,400	£ 5.67		23 Feb 2004	23 Feb 2011
	EXEC	160,000			160,000	£ 5.72		18 Feb 2005	18 Feb 2012
	EDIP	220,000		220,000		£ 3.88	£5.88	17 Feb 2004	17 Feb 2010
	EDIP	275,000			275,000	£ 4.22		25 Feb 2005	25 Feb 2011
I C Conn	SAYE	1,186		1,186		£ 3.86	£5.74	01 Sep 2009	28 Feb 2010
	SAYE	1,498			1,498	£ 4.41		01 Sep 2010	28 Feb 2011
	SAYE	617			617	£ 4.87		01 Sep 2011	01 Feb 2012
	SAYE		605		605	£ 4.20		01 Sep 2012	28 Feb 2013
	EXEC	72,250			72,250	£ 5.67		23 Feb 2004	23 Feb 2011
	EXEC	130,000			130,000	£ 5.72		18 Feb 2005	18 Feb 2012
R W Dudley[b c]	BP SOP	1,800			1,800	$ 48.94		28 Mar 2003	27 Mar 2010
	BP SOP	6,460			6,460	$ 49.65		23 Feb 2004	22 Feb 2011
	BP SOP	1,073			1,073	$ 43.82		17 Dec 2004	16 Dec 2011
	BP SOP	17,835			17,835	$ 48.99		18 Feb 2005	17 Feb 2012
	BP SOP	17,835			17,835	$ 38.10		17 Feb 2006	16 Feb 2013

Dr B E Grote[b]	BPA	10,404		-[d]	$ 53.90		15 Mar 2000	14 Mar 2009
	BPA	12,600		12,600	$ 48.94		28 Mar 2001	27 Mar 2010
	EDIP	58,173		-[d]	$ 48.82		18 Feb 2003	18 Feb 2009
	EDIP	58,173	45,000	13,173[e]	$ 37.76	$57.28-$59.50	17 Feb 2004	17 Feb 2010
	EDIP	58,333		58,333	$ 48.53		25 Feb 2005	25 Feb 2011
A G Inglis	SAYE	4,550	4,550		£ 3.50	£4.86	01 Sep 2008	28 Feb 2009
	EXEC	72,250		72,250	£ 5.67		23 Feb 2004	22 Feb 2011
	EXEC	119,000		119,000	£ 5.72		18 Feb 2005	17 Feb 2012
	EXEC	119,000		119,000	£ 3.88		17 Feb 2006	16 Feb 2013
	EXEC	100,500		100,500	£ 4.22		25 Feb 2007	24 Feb 2014

The closing market prices of an ordinary share and of an ADS on 31 December 2009 were £6.00 and $57.97 respectively.

During 2009, the highest market prices were £6.09 and $59.93 respectively and the lowest market prices were £4.05 and $34.14 respectively.

BPA = BP Amoco share option plan, which applied to US executive directors prior to the adoption of the EDIP.

EDIP = Executive Directors   Incentive Plan adopted by shareholders in April 2005 as described on page 80.

EXEC = Executive Share Option Scheme. These options were granted to the relevant individuals prior to their appointments as directors and are not subject to performance conditions.

SAYE = Save As You Earn employee share scheme.

BP SOP = BP Share Option Plan. These options were granted to Mr Dudley prior to his appointment as a director and are not subject to performance conditions.

[a]This information has been subject to audit.

[b]Numbers shown are ADSs under option. One ADS is equivalent to six ordinary shares.

[c]On appointment to the board.

[d]Options lapsed.

[e]Options exercised on 12 February 2010 at a market price of $54.36 per ADS.

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Service contracts

Director	Contract date	Salary as at 31 Dec 2009
Dr A B Hayward	29 Jan 2003	£ 1,045,000
I C Conn	22 Jul 2004	£690,000
Mr R Dudley	6 Apr 2009	$ 1,000,000
Dr B E Grote	7 Aug 2000	$ 1,380,000
A G Inglis	1 Feb 2007	£690,000

Service contracts have a notice period of one year and may be terminated by the company at any time with immediate effect on payment in lieu of notice equivalent to one year s salary or the amount of salary that would have been paid if the contract had been terminated on the expiry of the remainder of the notice period. The service contracts are expressed to expire at a normal retirement age of 60 (subject to age discrimination).

Dr Grote s contract is with BP Exploration (Alaska) Inc. He is seconded to BP p.l.c. under a secondment agreement of 7 August 2000, which expires at the date of the 2011 Annual General Meeting.

Mr Dudley s contract is with BP Corporation North America Inc. He is seconded to BP p.l.c. under a secondment agreement of 15 April 2009 which expires on 15 April 2012. Both secondments can be terminated by one month s notice by either party and terminate automatically on the termination of their service contracts.

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

All service contracts include a provision to allow for severance payments to be phased, when appropriate. The committee will also consider mitigation to reduce compensation to a departing director, when appropriate to do so.

Executive directors external appointments

The board encourages executive directors to broaden their knowledge and experience by taking up appointments outside the company. Each executive director is permitted to accept one non-executive appointment, from which they may retain any fee. External appointments are subject to agreement by the chairman and reported to the board. Any external appointment must not conflict with a director s duties and commitments to BP.

During the year, the fees received by executive directors for external appointments were as follows:

Executive director	Appointee company	Additional position held at appointee company	Total fees
Dr A B Hayward	Tata Steel[a]	Senior Independent Director	£29,000
I C Conn	Rolls-Royce	Senior	£65,000

		Independent Director	
Dr B E Grote	Unilever	Audit committee member	Unilever PLC £36,000 Unilever NV 52,250
A G Inglis	BAE Systems	Chair of Corporate Responsibility Committee	£90,000

[a] Member of Tata Steel Europe board until 1 April 2009 and Tata Steel Ltd board until 18 September 2009.

Remuneration committee

All the members of the committee are independent non-executive directors. Throughout the year, Dr Julius (chairman), and Sir Ian Prosser were members. Mr Davis and Sir Tom McKillop served on the committee until April 2009 and were succeeded by Mr Burgmans and Mr David in May 2009. The group chief executive was consulted on matters relating to the other executive directors who report to him and on matters relating to the performance of the company; neither he nor the chairman were present when matters affecting their own remuneration were discussed.

The remuneration committee s tasks, as set out in the board governance principles, are:

- To determine, on behalf of the board, the terms of engagement and remuneration of the group chief executive and the executive directors and to report on these to the shareholders.

- To determine, on behalf of the board, matters of policy over which the company has authority regarding the establishment or operation of the company s pension scheme of which the executive directors are members.

- To nominate, on behalf of the board, any trustees (or directors of corporate trustees) of the scheme.

- To review the policies being applied by the group chief executive in remunerating senior executives other than executive directors to ensure alignment and proportionality.

- To recommend to the board the quantum and structure of remuneration for the chairman.

Directors remuneration report

Constitution and operation
Each member of the remuneration committee is subject to annual re-election as a director of the company. The board considers all committee members to be independent (see page 68).

They have no personal financial interest, other than as shareholders, in the committee s decisions.

The committee met eight times in the period under review. The chairman of the board attends meetings of the committee and Mr Svanberg attended meetings prior to becoming chairman on 1 January 2010.

The committee is accountable to shareholders through its annual report on executive directors remuneration. It will consider the outcome of the vote at the AGM on the directors remuneration report and take into account the views of shareholders in its future decisions. The committee values its dialogue with major shareholders on remuneration matters.

Advice
Mr Aronson, an independent consultant, is the committee s secretary and independent adviser. Advice was also received from Mr Jackson, the company secretary, and from the company secretary s office, which is independent of executive management and reports to the chairman of the board.

The committee also appoints external advisers to provide specialist advice and services on particular remuneration matters. The independence of the advice is subject to annual review.

In 2009, the committee continued to engage Towers Watson as its principal external adviser. Towers Watson also provided other remuneration and benefits advice to parts of the group.

Freshfields Bruckhaus Deringer LLP provided legal advice on specific matters to the committee, as well as providing some legal advice to the group.

Ernst & Young reviewed the calculations on the financial-based targets that form the basis of the performance-related pay for executive directors, that is, the annual bonus and share element awards described on page 79, to ensure they met an independent, objective standard. They also provided audit, audit-related and taxation services for the group.

Part 3 Non-executive directors remuneration
The board sets the level of remuneration for all non-executive directors within a limit approved from time to time by shareholders. Key elements of BP s policy on non-executive director remuneration include:

- Remuneration should be sufficient to attract and retain world-class non-executive talent.
- Remuneration of non-executive directors is proposed by the chairman and agreed by the board.
- Remuneration practice should be consistent with recognized best practice standards for non-executive directors remuneration.
- Remuneration should be in the form of cash fees, payable monthly.
- Non-executive directors should not receive share options from the company.
- Non-executive directors are encouraged to establish a holding in BP shares of the equivalent value of one year s base fee.

Process
BP reviews the quantum and structure of chairman and non-executive remuneration on an annual basis. The chairman s remuneration is reviewed by the remuneration committee, which makes a recommendation to the board; the chairman does not vote on his own remuneration. Non-executive director remuneration is reviewed by the chairman, who makes a recommendation to the board; non-executive directors do not vote on their own remuneration.

2009 review of chairman and non-executive director remuneration
In 2009, the chairman reviewed non-executive director remuneration taking into account the review completed in 2008. The chairman made a recommendation to the board (which was agreed) to maintain the 2008 structure until a further review in 2010.

Carl-Henric Svanberg was appointed to the board in September 2009. At the time of his appointment, the remuneration committee looked at a comparison of remuneration for FTSE and international chairmen in determining his fee. The committee determined that in common with the previous chairman, he should receive the use of a chauffeured car, a maintained office for company business and security advice. In addition, the committee recognized that the appointment was to be Mr Svanberg s main commitment and as he would be performing a proportion of his duties from Sweden, limited but appropriate secretarial support in Sweden would be provided. Mr Svanberg is also eligible for a single relocation allowance of up to £100,000 to cover expenses incurred in relocating to London from Sweden.

Mr Svanberg received the basic non-executive director fee and transatlantic attendance allowance for the period between his appointment and his assumption of the role of chairman on 1 January 2010. On his appointment as chairman in 2010, the chairman s fee increased to £750,000.

Directors remuneration report

Fee structure

The table below shows the fee structure for non-executive directors on 1 January 2010:

	£ thousand
	Fee level
Chairman[a]	750
Senior independent director[b]	120
Board member	75
Audit committee and SEEAC chairmanship fees[c]	30
Remuneration committee chairmanship fee[c]	20
Committee membership fee[d]	5
Transatlantic attendance allowance	5

[a] The chairman remains ineligible for committee chairmanship and membership fees or transatlantic attendance allowance.

[b] The senior independent director is eligible for committee chairmanship fees and transatlantic attendance allowance plus any committee membership fees.

[c] Committee chairmen do not receive an additional membership fee for the committee they chair.

[d] For members of the SEEAC, audit and remuneration committees.

Remuneration of non-executive directors in 2009[a]

		£ thousand
	2008	**2009**
P D Sutherland	600	**600**
A Burgmans	90	**93**
Sir William Castell	108	**115**
C B Carroll	93	**90**
G David[b]	100	**118**
E B Davis, Jr	105	**105**
D J Flint	90	**85**
Dr D S Julius	110	**105**
Sir Ian Prosser	170	**165**
C-H Svanberg[c]	n/a	**30**
Directors leaving the board in 2009		
Sir Tom McKillop	95	**33**

[a] This information has been subject to audit.

[b] Also received £4,166 for serving as a member of BP s technology advisory committee.

[c] Appointed on 1 September 2009.

While fees were held at 2008 levels, in 2009 actual fees paid to non-executive directors were affected by changes in committee membership and the number of transatlantic meetings to which an attendance allowance was paid.

No share or share option awards were made to any non-executive director in respect of service to the board during 2009.

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

Superannuation gratuities

Until 2002, BP maintained a long-standing practice whereby non-executive directors who retired from the board after at least six years service were eligible for consideration for a superannuation gratuity. The board was, and continues to be, authorized to make such payments under the company s Articles of Association. In 2002, the board revised its policy so that non-executive directors appointed to the board after 1 July 2002 would not be eligible for a superannuation gratuity, and that directors in service at that date would remain eligible but service past 1 July 2002 would not be taken into account by the board in considering the amount of the superannuation gratuity.

The amount of the superannuation gratuity is calculated according to the following:

Service on the board is taken up to 1 July 2002.

Payment is calculated as 10% of the total remuneration received in either the year to 1 July 2002 or calendar year 2001 (whichever is the greater) multiplied by the number of years a non-executive director served on the board until 1 July 2002.

There is a limit on the payment equivalent to a maximum of 10 years service.

Peter Sutherland, who retired on 31 December 2009, is entitled to a superannuation gratuity of £280,000 in line with the policy arrangements agreed in 2002 and outlined above. Mr Sutherland has asked that the full balance of the gratuity be donated to an educational foundation.

Non-executive directors of Amoco Corporation

Non-executive directors who were formerly non-executive directors of Amoco Corporation have residual entitlements under the Amoco Non-Employee Directors Restricted Stock Plan. Directors were allocated restricted stock in remuneration for their service on the board of Amoco Corporation prior to its merger with BP in 1998. On merger, interests in Amoco shares in the plan were converted into interests in BP ADSs. The restricted stock will vest on the retirement of the non-executive director at the age of 70 (or earlier at the discretion of the board). Since the merger, no further entitlements have accrued to any director under the plan. The residual interests, as interests in a long-term incentive scheme, are set out in the table below:

	Interest in BP ADSs at 1 Jan 2009 and 31 Dec 2009[a]	Date on which director reaches age 70[b]
E B Davis, Jr	4,490	5 Aug 2014

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

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

Past directors

Mr Miles (who was a non-executive director of BP until April 2006) was appointed as a director and non-executive chairman of BP Pension Trustees Limited in October 2006. During 2009, he received £150,000 for this role.

Dr Walter Massey (who retired as a non-executive director of BP in April 2008) was appointed to the BP America External Advisory Council in April 2008 for a period of two years. During 2009, he received US$93,750 for this role.

This directors remuneration report was approved by the board and signed on its behalf by David J Jackson, company secretary, on 26 February 2010.

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Critical accounting policies

The significant accounting policies of the group are summarized in Financial statements Note 1 on page 114.

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for BP management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from the estimates and assumptions used. The following summary provides more information about the critical accounting policies that could have a significant impact on the results of the group and should be read in conjunction with the Notes on financial statements.

The accounting policies and areas that require the most significant judgements and estimates used in the preparation of the consolidated financial statements are in relation to oil and natural gas accounting, including the estimation of reserves, the recoverability of asset carrying values, taxation, derivative financial instruments, provisions and contingencies, and pensions and other post-retirement benefits.

Oil and natural gas accounting

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

The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred.

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration.

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

It is not unusual to have exploration wells and exploratory-type stratigraphic test wells remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and natural gas field is performed or while the optimum development plans and timing are established.

All such carried costs are subject to regular technical, commercial and management review on at least an annual basis to confirm the continued intent to develop, or otherwise extract value from, the discovery. Where this is no longer the case, the costs are immediately expensed.

Once a project is sanctioned for development, the carrying values of exploration licence and leasehold property acquisition costs and costs associated with exploration wells and exploratory-type stratigraphic test wells, are transferred to production assets within property, plant and equipment.

The capitalized exploration and development costs for proved oil and natural gas properties (which include the costs of drilling unsuccessful wells) are amortized on the basis of oil-equivalent barrels that are produced in a period as a percentage of the estimated proved reserves. Field development costs subject to depreciation are expenditures incurred to date, together with approved future development expenditure required to develop reserves.

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

Producing wells proved developed reserves.

Licence and property acquisition, field development and future decommissioning costs total proved reserves.

The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining carrying value of the asset over the expected future production. If proved reserves estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down of the property s carrying value (*see discussion of recoverability of asset carrying values on the following page*).

On 31 December 2008, the SEC published a revision of Rule 4-10 (a) of Regulation S-X for the estimation of reserves. These revised rules form the basis of the 2009 year-end estimation of proved reserves and the application of the technical aspects resulted in an immaterial increase of less than 1% to BP s total proved reserves. The estimation of oil and natural gas reserves and BP s process to manage reserves bookings is described in Exploration and Production Reserves and production on page 20, which is unaudited. As discussed on the following page, oil and natural gas reserves have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements.

The 2009 movements in proved reserves are reflected in the tables showing movements in oil and gas reserves by region in Financial statements Supplementary information on oil and natural gas (unaudited) on pages 183 to 197.

Recoverability of asset carrying values

BP assesses its fixed assets, including goodwill, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable and, as a result, charges for impairment are recognized in the group s results from time to time. Such indicators include changes in the group s business plans, changes in commodity prices leading to unprofitable performance, low plant utilization, evidence of physical damage and, for oil and natural gas properties, significant downward revisions of estimated volumes or increases in estimated future development expenditure. If there are low oil prices, natural gas prices, refining margins or marketing margins during an extended period, the group may need to recognize significant impairment charges.

The assessment for impairment entails comparing the carrying value of the asset or cash-generating unit with its recoverable amount, that is, the higher of fair value less costs to sell and value in use. Value in use is usually determined on the basis of discounted estimated future net cash flows.

Additional information for shareholders

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

For oil and natural gas properties, the expected future cash flows are estimated based on the group s plans to continue to develop and produce proved reserves and associated risk-adjusted probable and possible volumes. Expected future cash flows from the sale or production of these volumes are calculated based on the management s best estimate of future oil and natural gas prices. Prices for oil and natural gas used for future cash flow calculations are based on market prices for the first five years and the group s long-term planning assumptions thereafter. As at 31 December 2009, the group s long-term planning assumptions were $75 per barrel for Brent and $7.50/mmBtu for Henry Hub (2008 $75 per barrel and $7.50/mmBtu). These long-term planning assumptions are subject to periodic review and modification. The estimated future level of production is based on assumptions about future commodity prices, lifting and development costs, field decline rates, market demand and supply, economic regulatory climates and other factors.

The future cash flows are adjusted for risks specific to the cash-generating unit and are discounted using a pre-tax discount rate. The discount rate is derived from the group s post-tax weighted average cost of capital and is adjusted where applicable to take into account any specific risks relating to the country where the cash-generating unit is located, although other rates may be used if appropriate to the specific circumstances. In 2009 the rates ranged from 9% to 13% (2008 11% to 13%). The rate applied in each country is re-assessed each year by analysing relevant information.

Irrespective of whether there is any indication of impairment, BP is required to test annually for impairment of goodwill acquired in a business combination. The group carries goodwill of approximately $8.6 billion on its balance sheet (2008 $9.9 billion), principally relating to the Atlantic Richfield and Burmah Castrol acquisitions. In testing goodwill for impairment, the group uses a similar approach to that described above. If there are low oil prices or natural gas prices or refining margins or marketing margins for an extended period, the group may need to recognize significant goodwill impairment charges. In 2009, an impairment loss of $1.6 billion was recognized to write off all of the goodwill allocated to the US West Coast fuels value chain. The prevailing weak refining environment, together with a review of future margin expectations in the FVC, led to a reduction in the expected future cash flows.

Taxation

The computation of the group s income tax expense involves the interpretation of applicable tax laws and regulations in many jurisdictions throughout the world. The resolution of tax positions taken by the group, through negotiations with relevant tax authorities or through litigation, can take several years to complete and in some cases it is difficult to predict the ultimate outcome.

In addition, the group has carry-forward tax losses in certain taxing jurisdictions that are available to offset against future taxable profit. However, deferred tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused tax losses can be utilized. Management judgement is exercised in assessing whether this is the case.

To the extent that actual outcomes differ from management s estimates, taxation charges or credits may arise in future periods. For more information see Financial statements Note 16 on page 135 and Note 41 on page 174.

Derivative financial instruments

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices as well as for trading purposes. In addition, derivatives embedded within other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of the host contract. All such derivatives are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Gains and losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

In some cases the fair values of derivatives are estimated using models and other valuation methods due to the absence of quoted prices or other observable, market-corroborated data. In particular, this applies to the majority of the group s natural gas embedded derivatives. These are primarily long-term UK gas contracts that use pricing formulas not related to gas prices, for example, oil product and power prices. These contracts are valued using models with inputs that include price curves for each of the different products that are built up from active market pricing data and extrapolated to the expiry of the contracts using the maximum available external pricing information. Additionally, where limited data exists for certain products, prices are interpolated using historic and long-term pricing relationships. Price volatility is also an input for the models. Changes in the key assumptions could have a material impact on the gains and losses on embedded derivatives recognized in the income statement. For more information see Financial statements Note 31 on page 150. An analysis of the sensitivity of the fair value of the embedded derivatives to changes in the key assumptions is provided in Financial statements Note 24 on page 142.

Provisions and contingencies

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

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

The timing and amount of future expenditures are reviewed annually, together with the interest rate used in discounting the cash flows. The interest rate used to determine the balance sheet obligation at the end of 2009 was 1.75% (2008 2%). The interest rate represents the real rate (i.e. excluding the impacts of inflation) on long-dated government bonds.

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

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

Provisions for environmental remediation are made when a cleanup is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provision for environmental liabilities is estimated based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

The provision for environmental liabilities is reviewed at least annually. The interest rate used to determine the balance sheet obligation at 31 December 2009 was 1.75% (2008 2%).

As further described in Financial statements Note 41 on page 174, the group is subject to claims and actions. The facts and circumstances relating to particular cases are evaluated regularly in determining whether it is probable that there will be a future outflow of funds and, once established, whether a provision relating to a specific litigation should be adjusted. Accordingly, significant management judgement relating to contingent liabilities is required, since the outcome of litigation is difficult to predict.

Pensions and other post-retirement benefits

Accounting for pensions and other post-retirement benefits involves judgement about uncertain events, including estimated retirement dates, salary levels at retirement, mortality rates, rates of return on plan assets, determination of discount rates for measuring plan obligations, healthcare cost trend rates and rates of utilization of healthcare services by retirees.

These assumptions are based on the environment in each country. Determination of the projected benefit obligations for the group s defined benefit pension and post-retirement plans is important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The assumptions used may vary from year to year, which will affect future results of operations. Any differences between these assumptions and the actual outcome also affect future results of operations.

Pension and other post-retirement benefit assumptions are reviewed by management at the end of each year. These assumptions are used to determine the projected benefit obligation at the year-end and hence the surpluses and deficits recorded on the group s balance sheet, and pension and other post-retirement benefit expense for the following year.

The pension and other post-retirement benefit assumptions at December 2009, 2008 and 2007 are provided in Financial statements Note 35 on page 159.

The assumed rate of investment return, discount rate and the US healthcare cost trend rate have a significant effect on the amounts reported. A sensitivity analysis of the impact of changes in these assumptions on the benefit expense and obligation is provided in Financial statements Note 35 on page 159.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. Mortality assumptions reflect best practice in the countries in which we provide pensions and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. A sensitivity analysis of the impact of changes in the mortality assumptions on the benefit expense and obligation is provided in Financial statements Note 35 on page 159.

Property, plants and equipment

BP has freehold and leasehold interests in real estate in numerous countries, but no individual property is significant to the group as a whole. See Exploration and Production on page 18 for a description of the group s significant reserves and sources of crude oil and natural gas. Significant plans to construct, expand or improve specific facilities are described under each of the business headings within this section.

Share ownership

Directors and senior management

As at 18 February 2010, the following directors of BP p.l.c. held interests in BP ordinary shares of 25 cents each or their calculated equivalent as set out below:

I C Conn	349,820	2,016,005[a]	266,904[b]
R W Dudley	276,846	1,120,716[a]	
Dr B E Grote	1,351,529	2,376,570[a]	
Dr A B Hayward	622,807	3,022,598[a]	
A G Inglis	308,639	2,016,005[a]	266,904[b]
P Anderson	6,000		
A Burgmans	10,156		
C B Carroll	10,500		
Sir William Castell	82,500		
G David	39,000		
E B Davis, Jr	76,497		
D J Flint	15,000		
Dr D S Julius	15,000		
Sir Ian Prosser	16,301		
C-H Svanberg	750,000		

[a]Performance shares awarded under the BP Executive Directors Incentive Plan. These figures represent the maximum possible vesting levels. The actual number of shares/ADSs that vest will depend on the extent to which performance conditions have been satisfied over a three-year period.

[b]Restricted share award under the BP Executive Directors Incentive Plan. These shares will vest in two equal tranches after three and five years, subject to the directors continued service and satisfactory performance.

Additional information for shareholders

As at 18 February 2010, the following directors of BP p.l.c. held options under the BP group share option schemes for ordinary shares or their calculated equivalent as set out below:

I C Conn	204,970
R W Dudley	270,018
Dr B E Grote	425,598
Dr A B Hayward	549,620
A G Inglis	410,750

There are no directors or members of senior management who own more than 1% of the ordinary shares outstanding. At 18 February 2010, all directors and senior management as a group held interests in 5,649,017 ordinary shares or their calculated equivalent, 12,173,702 performance shares or their calculated equivalent and 2,113,316 options for ordinary shares or their calculated equivalent under the BP group share options schemes.

Additional details regarding the options granted and performance shares awarded can be found in the directors remuneration report on pages 84 and 85.

Employee share plans

The following table shows employee share options granted.

			options thousands
	2009	2008	2007
Employee share options granted during the year[a]	**9,680**	8,063	6,004

[a]For the options outstanding at 31 December 2009, the exercise price ranges and weighted average remaining contractual lives are shown in Financial statements Note 38 on page 170.

BP offers most of its employees the opportunity to acquire a shareholding in the company through savings-related and/or matching share plan arrangements. BP also uses performance plans (*see Financial statements Note 38 on page 170*) as elements of remuneration for executive directors and senior employees.

Shares acquired through the company s employee share plans rank pari passu with shares in issue and have no special rights, save as described below. For legal and practical reasons, the rules of these plans set out the consequences of a change of control of the company, and generally provide for options and conditional awards to vest on an accelerated basis.

Savings and matching plans

BP ShareSave Plan

This is a savings-related share option plan under which employees save on a monthly basis, over a three- or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and options are granted annually, usually in June. Participants leaving for a qualifying reason will have six months in which to use their savings to exercise their options on a pro-rated basis.

BP ShareMatch plans

These are matching share plans under which BP matches employees own contributions of shares up to a predetermined limit. The plans are run in the UK and in more than 70 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. In other countries the plan is run on an annual basis with shares being held in trust for three years. The plan is operated on a cash basis in those countries where there are regulatory restrictions preventing the holding of BP shares. When the employee leaves BP all shares must be removed from trust and units under the plan operated on a cash basis must be encashed.

Once shares have been awarded to an employee under the plan, the employee may instruct the trustee how to vote their shares.

Local plans

In some countries, BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances.

Cash-settled share-based payments

Grants are settled in cash where participants are located in a country whose regulatory environment prohibits the holding of BP shares.

Employee share ownership plans (ESOPs)

ESOPs have been established to hold BP shares to satisfy any releases made to participants under the Executive Directors Incentive Plan, the Long-Term Performance Plan and the Share Option plans. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the group. Pending vesting, the ESOPs have independent trustees that have the discretion in relation to the voting of such shares. Until such time as the company s own shares held by the ESOP trusts vest unconditionally in employees, the amount paid for those shares is deducted in arriving at shareholders equity (*see Financial statements Note 37 on page 166*). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2009, the ESOPs held 18,062,246 shares (2008 29,051,082 shares and 2007 6,448,838 shares) for potential future awards, which had a market value of $174 million (2008 $220 million and 2007 $79 million).

Pursuant to the various BP group share option schemes, the following options for ordinary shares of the company were outstanding at 18 February 2010:

Options outstanding (shares)	Expiry dates of options	Exercise price per share
285,364,691	2010-2016	$6.18-$11.92

More details on share options appear in Financial statements Note 38 on page 170.

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Additional information for shareholders

Major shareholders and related
party transactions

**Register of members holding BP ordinary shares as at
31 December 2009**

Range of holdings	Number of ordinary shareholders	Percentage of total ordinary shareholders	Percentage of total ordinary share capital
1-200	57,927	18.43	0.02
201-1,000	116,624	37.11	0.30
1,001-10,000	126,034	40.10	1.83
10,001-100,000	11,867	3.77	1.17
100,001-1,000,000	1,065	0.34	1.85
Over 1,000,000[a]	777	0.25	94.83
Totals	314,294	100.00	100.00

[a] Includes JPMorgan Chase Bank holding 27.74% of the total ordinary issued share capital (excluding shares held in treasury) as the approved depositary for ADSs, a breakdown of which is shown in the table below.

**Register of holders of American depositary shares (ADSs) as at
31 December 2009[a]**

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	72,272	54.22	0.48
201-1,000	37,695	28.28	2.08
1,001-10,000	21,893	16.42	6.80
10,001-100,000	1,417	1.06	2.81
100,001-1,000,000	22	0.02	0.43
Over 1,000,000[b]	1	0.00	87.4
Totals	133,300	100.00	100.00

[a]One ADS represents six 25 cent ordinary shares.

[b]One of the holders of ADSs represents some 698,373 underlying shareholders.
As at 31 December 2009, there were also 1,660 preference shareholders. Preference shareholders represented 0.4% and ordinary shareholders represented 99.6% of the total issued nominal share capital of the company as at that date.

Substantial shareholdings

The disclosure of certain major interests in the share capital of the company is governed by the Disclosure and Transparency Rules (DTR) made by the UK Financial Services Authority and the US Securities Exchange Act of 1934. Under DTR 5, we have received notification that BlackRock, Inc. holds 5.93% of the voting rights of the issued share capital of the company; and Legal and General Group Plc holds 4.18% of the voting rights of the issued share capital of the company.

As at the date of this report, the company had been notified that JPMorgan Chase Bank, as depositary for American depositary shares (ADSs) holds interests through its nominee, Guaranty Nominees Limited, in 5,318,457,873 ordinary shares (28.34% of the company s ordinary share capital excluding shares held in Treasury and shares bought back for cancellation). During 2009, BlackRock, Inc. acquired Barclays Global Investors, resulting in an increase in the share interest of BlackRock, Inc. BlackRock, Inc. holds interests in 1,112,967,596 ordinary shares (5.93% of the ordinary share capital excluding shares held in treasury and shares bought back for cancellation). Legal & General Group plc hold interests in 783,820,456 ordinary shares (4.18% of the company s ordinary share capital excluding shares held in treasury and shares bought back for cancellation). The company s major shareholders do not have different voting rights.

At the date of this report the company has also been notified of the following interests in preference shares: The National Farmers Union Mutual Insurance Society Limited holds interests in 945,000 8% cumulative first preference shares (13.07% of that class) and 987,000 9% cumulative second preference shares (18.03% of that class). M & G Investment Management Ltd. holds interests in 528,150 8% cumulative first preference shares (7.30% of that class) and 644,450 9% cumulative second preference shares (11.77% of that class). Gartmore Investment Management Limited holds interests in 394,538 8% cumulative first preference shares (5.45% of that class) and 500,000 9% cumulative second preference shares (9.14% of that class). Duncan Lawrie Ltd. holds interests in 461,876 8% cumulative first preference shares (6.39% of that class). Ruffer LLP holds interests in 587,000 9% cumulative second preference shares (10.72% of that class). Lazard Asset Management Ltd. (U.K.) holds interests in 328,500 9% cumulative second preference shares (6.0% of that class).

The total preference shares in issue comprise only 0.4% of the company s total issued nominal share capital, the rest being ordinary shares.

Related-party transactions

Transactions between the group and its significant jointly controlled entities and associates are summarized in Financial statements Note 22 on page 140 and Financial statements Note 23 on page 141. In the ordinary course of its business, the group enters into transactions with various organizations with which certain of its directors or executive officers are associated. Except as described in this report, the group did not have material transactions or transactions of an unusual nature with, and did not make loans to, related parties in the period commencing 1 January 2009 to 18 February 2010.

Dividends

BP has paid dividends on its ordinary shares in each year since 1917. In 2000 and thereafter, dividends were, and are expected to continue to be, paid quarterly in March, June, September and December. Former Amoco Corporation and Atlantic Richfield Company shareholders will not be able to receive dividends, or proxy material, until they send in their Amoco Corporation or Atlantic Richfield Company common shares for exchange.

BP currently announces dividends for ordinary shares in US dollars and states an equivalent pounds sterling dividend. Dividends on BP ordinary shares will be paid in pounds sterling and on BP ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the forward exchange rate in London over the five business days prior to the announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced, but it is not the company s intention to change its current policy of announcing dividends on ordinary shares in US dollars.

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The following table shows dividends announced and paid by the company per ADS for each of the past five years.

		March	June	September	December	Total
Dividends per American depositary share						
2005	UK pence	27.1	26.7	30.7	30.4	114.9
	US cents	51.0	51.0	53.55	53.55	209.1
	Canadian cents	64.0	63.2	65.3	63.7	256.2
2006	UK pence	31.7	31.5	31.9	31.4	126.5
	US cents	56.25	56.25	58.95	58.95	230.4
	Canadian cents	64.5	64.1	67.4	66.5	262.5
2007	UK pence	31.5	30.9	31.7	31.8	125.9
	US cents	61.95	61.95	64.95	64.95	253.8
	Canadian cents	73.3	69.5	67.8	63.6	274.2
2008	UK pence	40.9	41.0	42.2	52.2	176.3
	US cents	81.15	81.15	84.0	84.0	330.3
	Canadian cents	80.8	82.5	85.8	108.6	357.7
2009	**UK pence**	**58.91**	**57.50**	**51.02**	**51.07**	**218.5**
	US cents	**84**	**84**	**84**	**84**	**336**
	Canadian cents[a]	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**

[a] BP shares were de-listed from the Toronto Stock Exchange on 15 August 2008 and the last dividend payment in Canadian dollars was made on 8 December 2008.

A dividend reinvestment plan is in place whereby holders of BP ordinary shares can elect to reinvest the net cash dividend in shares purchased on the London Stock Exchange. This plan is not available to any person resident in the US or Canada or in any jurisdiction outside the UK where such an offer requires compliance by the company with any governmental or regulatory procedures or any similar formalities. A dividend reinvestment plan is, however, available for holders of ADSs through JPMorgan Chase Bank. Subject to shareholder approval at the Annual General Meeting, the company is seeking to replace these plans with an optional Scrip Dividend Programme. If approved, the requirements of the programme mean that there will be certain changes to our current dividend timetable.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on pages 14-16 and other matters that may affect the business of the group set out in Financial performance on page 49 and in Liquidity and capital resources on page 57.

Legal proceedings

BP America Inc. (BP America) continues to be subject to oversight by an independent monitor, who has authority to investigate and report alleged violations of the US Commodity Exchange Act or US Commodity Futures Trading Commission (CFTC) regulations and to recommend corrective action. The appointment of the independent monitor was a condition of the deferred prosecution agreement (DPA) entered into with the US Department of Justice (DOJ) on 25 October 2007 relating to allegations that BP America manipulated the price of February 2004 TET physical propane and attempted to manipulate the price of TET propane in April 2003 and the companion consent order with the CFTC, entered the same day, resolving all criminal and civil enforcement matters pending at that time concerning propane trading by BP Products North America Inc. (BP Products). The DPA requires BP America s and certain of its affiliates continued co-operation with the US government investigations of the trades in question, as well as other trading matters that may arise. The DPA has a term of three years but can be extended by two additional one-year periods, and contemplates dismissal of all charges at the end of the term following the DOJ s determination that BP America has complied with the terms of the DPA. Investigations into BP s trading activities continue to be conducted from time to time.

Private complaints, including class actions, have also been filed against BP Products alleging propane price manipulation. The complaints contain allegations similar to those in the CFTC action as well as of violations of federal and state antitrust and unfair competition laws and state consumer protection statutes and unjust enrichment. The complaints seek actual and punitive damages and injunctive relief. Settlement in both groups of the class actions (the direct and indirect purchasers) have received final court approval. Two independent lawsuits from class members who opted out of the direct purchaser settlement are also pending. In addition, state actions alleging manipulation of propane and other energy commodity prices and seeking a variety of remedies have been filed against BP Products and other BP subsidiaries.

On 23 March 2005, an explosion and fire occurred in the isomerization unit of BP Products Texas City refinery as the unit was coming out of planned maintenance. Fifteen workers died in the incident and many others were injured. BP Products has resolved all civil injury claims arising from the March 2005 incident.

In March 2007, the US Chemical Safety and Hazard Investigation Board (CSB) issued its final report on the incident. The report contained recommendations to the Texas City refinery and to the board of the company. In May 2007, BP responded to the CSB s recommendations. BP and the CSB will continue to discuss BP s responses with the objective of the CSB agreeing to close-out its recommendations.

On 25 October 2007, the DOJ announced that it had entered into a criminal plea agreement with BP Products related to the March 2005 explosion and fire. On 4 February 2008, BP Products pleaded guilty, pursuant to the plea agreement, to one felony violation of the risk management planning regulations promulgated under the US federal Clean Air Act and on 12 March 2009, the court accepted the plea agreement. In connection with the plea agreement, BP Products paid a $50 million criminal fine and was sentenced to three years probation. Compliance with a 2005 US Occupational Safety and Health Administration (OSHA) settlement agreement and an agreed order entered into by BP Products with the Texas Commission on Environmental Quality (TCEQ) are conditions of probation. The DOJ continues to investigate certain other matters arising from the March 2005 explosion and fire.

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The Texas Office of Attorney General, on behalf of the TCEQ, has filed a petition against BP Products asserting certain air emission and reporting violations at the Texas City refinery from 2005 to 2009, including in relation to the March 2005 explosion and fire. BP is contesting the petition in a pending civil proceeding.

In September 2009, BP Products filed a petition to clarify specific required actions and deadlines under the 2005 Settlement Agreement with OSHA. That agreement resolved citations issued in connection with the March 2005 Texas City refinery explosion. OSHA has denied BP Products petition. This matter is scheduled for review by the Occupational Safety and Health (OSH) Review Commission. In October 2009 OSHA issued the Texas City Refinery citations seeking a total of $87.4 million civil penalty for alleged violations of the 2005 Agreement and alleged process safety management violations. BP Products has contested the citations so this will also be reviewed by the OSH Review Commission and possibly the federal courts. Settlement negotiations continue between BP Products and OSHA in an attempt to settle the citations for alleged violations of the 2005 settlement agreement.

BP has received a shareholder derivative action against various of its current and former officers and directors based on alleged violations of the US Clean Air Act and OSHA regulations at the Texas City refinery subsequent to the March 2005 explosion and fire.

BP is also defending civil personal injury claims by Texas City refinery workers or their families from incidents or releases since the March 2005 explosion and fire.

On 29 November 2007, BP Exploration (Alaska) Inc. (BPXA) entered into a criminal plea agreement with the DOJ relating to leaks of crude oil in March and August 2006. BPXA s guilty plea, to a misdemeanour violation of the US Federal Water Pollution Control Act, included a term of three years probation. BPXA is eligible to petition the court for termination of the probation term if it meets certain benchmarks relating to replacement of the transit lines, upgrades to its leak detection system and improvements to its integrity management programme. On 31 March 2009, the DOJ filed a complaint against BPXA seeking civil penalties and injunctive relief relating to the 2006 oil releases. The complaint alleges that BPXA violated various federal environmental and pipeline safety statutes and associated regulations in connection with the two releases and its maintenance and operation of North Slope pipelines. The State of Alaska also filed a complaint on 31 March 2009 against BPXA seeking civil penalties and damages relating to these events. The complaint alleges that the two releases and BPXA s corrosion management practices violated various statutory, contractual and common law duties to the State, resulting in penalty liability, damages for lost royalties and taxes, and liability for punitive damages.

Approximately 200 lawsuits were filed in state and federal courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP s combination with Atlantic Richfield. Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages that it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, BP will defend the claims vigorously.

Since 1987, Atlantic Richfield, a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting and Refining and another company that manufactured lead pigment during the period 1920-1946. Plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits seek various remedies including compensation to lead-poisoned children, cost to find and remove lead paint from buildings, medical monitoring and screening programmes, public warning and education of lead hazards, reimbursement of government healthcare costs and special education for lead-poisoned citizens and punitive damages.

No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgement in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences and it intends to defend such actions vigorously and that the incurrence of liability is remote. Consequently, BP believes that the impact of these lawsuits on the group s results of operations, financial position or liquidity will not be material.

For certain information regarding environmental proceedings, see Environment United States on page 44.

Share prices and listings

Markets and market prices

The primary market for BP s ordinary shares is the London Stock Exchange (LSE). BP s ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index. BP s ordinary shares are also traded on the Frankfurt stock exchange in Germany.

Trading of BP s shares on the LSE is primarily through the use of the Stock Exchange Electronic Trading Service (SETS), introduced in 1997 for the largest companies in terms of market capitalization whose primary listing is the LSE. Under SETS, buy and sell orders at specific prices may be sent to the exchange electronically by any firm that is a member of the LSE, on behalf of a client or on behalf of itself acting as a principal. The orders are then anonymously displayed in the order book. When there is a match on a buy and a sell order, the trade is executed and automatically reported to the LSE. Trading is continuous from 8.00 a.m. to 4.30 p.m. UK time but, in the event of a 20% movement in the share price either way, the LSE may impose a temporary halt in the trading of that company s shares in the order book to allow the market to re-establish equilibrium. Dealings in ordinary shares may also take place between an investor and a market-maker, via a member firm, outside the electronic order book.

In the US, the company s securities are traded in the form of ADSs, for which JPMorgan Chase Bank is the depositary (the Depositary) and transfer agent. The Depositary s principal office is 4 New York Plaza, Floor 13, New York, NY 10004, US. Each ADS represents six ordinary shares. ADSs are listed on the New York Stock Exchange. ADSs are evidenced by American depositary receipts (ADRs), which may be issued in either certificated or book entry form.

The following table sets forth for the periods indicated the highest and lowest middle market quotations for BP s ordinary shares for the periods shown. These are derived from the Daily Official List of the LSE and the highest and lowest sales prices of ADSs as reported on the New York Stock Exchange (NYSE) composite tape.

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	Pence		Dollars	
			American depositary	
	Ordinary shares		shares[a]	
	High	Low	High	Low
Year ended 31 December				
2005	686.00	499.00	72.75	56.60
2006	723.00	558.50	76.85	63.52
2007	640.00	504.50	79.77	58.62
2008	657.25	370.00	77.69	37.57
2009	613.40	400.00	60.00	33.71
Year ended 31 December				
2008: First quarter	648.00	495.00	75.87	57.87
Second quarter	657.25	501.34	77.69	60.25
Third quarter	583.00	446.00	69.10	48.35
Fourth quarter	541.25	370.00	51.49	37.57
2009: First quarter	**566.50**	**400.00**	**49.83**	**33.71**
Second quarter	**543.75**	**426.50**	**53.24**	**38.50**
Third quarter	**568.50**	**459.25**	**55.61**	**44.63**
Fourth quarter	**613.40**	**528.00**	**60.00**	**50.60**
2010: First quarter (to 18 February)	**639.00**	**552.30**	**62.38**	**52.11**
Month of				
September 2009	**568.50**	**514.80**	**55.61**	**50.30**
October 2009	**598.00**	**528.00**	**58.69**	**50.60**
November 2009	**599.30**	**562.50**	**60.00**	**56.22**
December 2009	**613.40**	**572.00**	**58.99**	**55.77**
January 2010	**639.00**	**585.10**	**62.38**	**55.87**
February 2010 (to 18 February)	**595.00**	**552.30**	**57.26**	**52.11**

[a] An ADS is equivalent to six 25 cent ordinary shares.

Market prices for the ordinary shares on the LSE and in after-hours trading off the LSE, in each case while the NYSE is open, and the market prices for ADSs on the NYSE are closely related due to arbitrage among the various markets, although differences may exist from time to time due to various factors, including UK stamp duty reserve tax.

On 18 February 2010, 886,409,646 ADSs (equivalent to 5,318,457,873 ordinary shares or some 28.34% of the total issued share capital, excluding treasury shares and shares bought back for cancellation) were outstanding and were held by approximately 132,684 ADS holders. Of these, about 131,204 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 698,373 underlying holders.

On 18 February 2010, there were approximately 314,028 holders of record of ordinary shares. Of these holders, around 1,540 had registered addresses in the US and held a total of some 4,343,899 ordinary shares.

Since certain of the ordinary shares and ADSs were held by brokers and other nominees, the number of holders of record in the US may not be representative of the number of beneficial holders or of their country of residence.

Memorandum and Articles
of Association

The following summarizes certain provisions of the company s Memorandum and Articles of Association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act and the company s Memorandum and Articles of Association. Information on where investors can obtain copies of the Memorandum and Articles of Association is described under the heading Documents on display on page 101.

At the AGM held on 17 April 2008, shareholders voted to adopt new Articles of Association, largely to take account of changes in UK company law brought about by the Companies Act 2006. Further amendments to the Articles of Association are being proposed at our AGM in 2010, to reflect the full implementation of the Companies Act 2006, among other matters.

Under the Companies Act 2006 the Memorandum serves a more limited role as historical evidence of the formation of the company. Since October 2009 the provisions of the company s Memorandum are deemed to form part of BP s Articles of Association.

Objects and purposes

BP is incorporated under the name BP p.l.c. and is registered in England and Wales with registered number 102498. Clause 4 of BP s Memorandum of Association provides that its objects include the acquisition of petroleum-bearing lands; the carrying on of refining and dealing businesses in the petroleum, manufacturing, metallurgical or chemicals businesses; the purchase and operation of ships and all other vehicles and other conveyances; and the carrying on of any other businesses calculated to benefit BP. The memorandum grants BP a range of corporate capabilities to effect these objects.

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Directors

The business and affairs of BP shall be managed by the directors.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which he has a material interest other than by virtue of his interest in shares in the company. However, in the absence of some other material interest not indicated below, a director is entitled to vote and to be counted in a quorum for the purpose of any vote relating to a resolution concerning the following matters:

- The giving of security or indemnity with respect to any money lent or obligation taken by the director at the request or benefit of the company.
- Any proposal in which he is interested concerning the underwriting of company securities or debentures.
- Any proposal concerning any other company in which he is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that he and persons connected with him are not the holder or holders of 1% or more of the voting interest in the shares of such company.
- Proposals concerning the modification of certain retirement benefits schemes under which he may benefit and that have been approved by either the UK Board of Inland Revenue or by the shareholders.
- Any proposal concerning the purchase or maintenance of any insurance policy under which he may benefit.

The UK Companies Act requires a director of a company who is in any way interested in a contract or proposed contract with the company to declare the nature of his interest at a meeting of the directors of the company. The definition of interest includes the interests of spouses, children, companies and trusts. The UK Companies Act also requires that a director must avoid a situation where a director has, or could have, a direct or indirect interest that conflicts, or possibly may conflict, with the company s interests. The Act allows directors of public companies to authorize such conflicts where appropriate, if a company s Articles of Association so permit. BP s Articles of Association permit the authorization of such conflicts. The directors may exercise all the powers of the company to borrow money, except that the amount remaining undischarged of all moneys borrowed by the company shall not, without approval of the shareholders, exceed the amount paid up on the share capital plus the aggregate of the amount of the capital and revenue reserves of the company. Variation of the borrowing power of the board may only be effected by amending the Articles of Association.

Remuneration of non-executive directors shall be determined in the aggregate by resolution of the shareholders. Remuneration of executive directors is determined by the remuneration committee. This committee is made up of non-executive directors only. There is no requirement of share ownership for a director s qualification.

Dividend rights; other rights to share in company profits; capital calls

If recommended by the directors of BP, BP shareholders may, by resolution, declare dividends but no such dividend may be declared in excess of the amount recommended by the directors. The directors may also pay interim dividends without obtaining shareholder approval. No dividend may be paid other than out of profits available for distribution, as determined under IFRS and the UK Companies Act. Dividends on ordinary shares are payable only after payment of dividends on BP preference shares. Any dividend unclaimed after a period of 12 years from the date of declaration of such dividend shall be forfeited and reverts to BP.

The directors have the power to declare and pay dividends in any currency provided that a sterling equivalent is announced. It is not the company s intention to change its current policy of paying dividends in US dollars.

Apart from shareholders rights to share in BP s profits by dividend (if any is declared), the Articles of Association provide that the directors may set aside:

A special reserve fund out of the balance of profits each year to make up any deficit of cumulative dividend on the BP preference shares.

A general reserve out of the balance of profits each year, which shall be applicable for any purpose to which the profits of the company may properly be applied. This may include capitalization of such sum, pursuant to an ordinary shareholders resolution, and distribution to shareholders as if it were distributed by way of a dividend on the ordinary shares or in paying up in full unissued ordinary shares for allotment and distribution as bonus shares.

Any such sums so deposited may be distributed in accordance with the manner of distribution of dividends as described above.

Holders of shares are not subject to calls on capital by the company, provided that the amounts required to be paid on issue have been paid off. All shares are fully paid.

Voting rights

The Articles of Association of the company provide that voting on resolutions at a shareholders meeting will be decided on a poll other than resolutions of a procedural nature, which may be decided on a show of hands. If voting is on a poll, every shareholder who is present in person or by proxy has one vote for every ordinary share held and two votes for every £5 in nominal amount of BP preference shares held. If voting is on a show of hands, each shareholder who is present at the meeting in person or whose duly appointed proxy is present in person will have one vote, regardless of the number of shares held, unless a poll is requested. Shareholders do not have cumulative voting rights.

Holders of record of ordinary shares may appoint a proxy, including a beneficial owner of those shares, to attend, speak and vote on their behalf at any shareholders meeting.

Record holders of BP ADSs are also entitled to attend, speak and vote at any shareholders meeting of BP by the appointment by the approved depositary, JPMorgan Chase Bank, of them as proxies in respect of the ordinary shares represented by their ADSs. Each such proxy may also appoint a proxy. Alternatively, holders of BP ADSs are entitled to vote by supplying their voting instructions to the depositary, who will vote the ordinary shares represented by their ADSs in accordance with their instructions.

Proxies may be delivered electronically.

Matters are transacted at shareholders meetings by the proposing and passing of resolutions, of which there are three types: ordinary, special or extraordinary. An annual general meeting must be held once in every year and all other general meetings will be called extraordinary general meetings.

An ordinary resolution requires the affirmative vote of a majority of the votes of those persons voting at a meeting at which there is a quorum. Special and extraordinary resolutions require the affirmative vote of not less than three-fourths of the persons voting at a meeting at which there is a quorum. Any AGM requires 21 days notice. The notice period for an extraordinary general meeting is 14 days. With the implementation of the EU Shareholder Rights Directive into UK law, reliance on this notice period of 14 days requires annual shareholder approval, failing which, a 21-day notice period will apply.

Additional information for shareholders

Liquidation rights; redemption provisions

In the event of a liquidation of BP, after payment of all liabilities and applicable deductions under UK laws and subject to the payment of secured creditors, the holders of BP preference shares would be entitled to the sum of (i) the capital paid up on such shares plus, (ii) accrued and unpaid dividends and (iii) a premium equal to the higher of (a) 10% of the capital paid up on the BP preference shares and (b) the excess of the average market price over par value of such shares on the LSE during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, BP may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolutions, by determination of the directors), and may issue shares that are to be or may be redeemed.

Variation of rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or on the adoption of an extraordinary resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the Articles of Association relating to proceedings at a general meeting apply, except that the quorum with respect to a meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one-third or more of the shares of that class.

Shareholders meetings and notices

Shareholders must provide BP with a postal or electronic address in the UK in order to be entitled to receive notice of shareholders meetings. In certain circumstances, BP may give notices to shareholders by advertisement in UK newspapers. Holders of BP ADSs are entitled to receive notices under the terms of the deposit agreement relating to BP ADSs. The substance and timing of notices is described above under the heading Voting Rights.

Under the Articles of Association, the AGM of shareholders will be held within the six-month period from the first day of BP s accounting period. All general meetings shall be held at a time and place determined by the directors within the UK. If any shareholders meeting is adjourned for lack of quorum, notice of the time and place of the meeting may be given in any lawful manner, including electronically. Powers exist for action to be taken either before or at the meeting by authorized officers to ensure its orderly conduct and safety of those attending.

Limitations on voting and shareholding

There are no limitations imposed by English law or the company s Memorandum or Articles of Association on the right of non-residents or foreign persons to hold or vote the company s ordinary shares or ADSs, other than limitations that would generally apply to all of the shareholders.

Disclosure of interests in shares

The UK Companies Act permits a public company, on written notice, to require any person whom the company believes to be or, at any time during the previous three years prior to the issue of the notice, to have been interested in its voting shares, to disclose certain information with respect to those interests. Failure to supply the information required may lead to disenfranchisement of the relevant shares and a prohibition on their transfer and receipt of dividends and other payments in respect of those shares. In this context the term interest is widely defined and will generally include an interest of any kind whatsoever in voting shares, including any interest of a holder of BP ADSs.

Exchange controls

There are currently no UK foreign exchange controls or restrictions on remittances of dividends on the ordinary shares or on the conduct of the company s operations.

There are no limitations, either under the laws of the UK or under the company s Articles of Association, restricting the right of non-resident or foreign owners to hold or vote BP ordinary or preference shares in the company.

Taxation

This section describes the material US federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder who holds the ordinary shares or ADSs as capital assets for tax purposes. It does not apply, however, to members of special classes of holders subject to special rules and holders that, directly or indirectly, hold 10% or more of the company s voting stock. In addition, if a partnership holds the shares or ADSs, the United States federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership, and may not be described fully below.

A US holder is any beneficial owner of ordinary shares or ADSs that is for US federal income tax purposes (i) a citizen or resident of the US, (ii) a US domestic corporation, (iii) an estate whose income is subject to US federal income taxation regardless of its source, or (iv) a trust if a US court can exercise primary supervision over the trust s administration and one or more US persons are authorized to control all substantial decisions of the trust.

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations thereunder, published rulings and court decisions, and the taxation laws of the UK, all as currently in effect, as well as the income tax convention between the US and the UK that entered into force on 31 March 2003 (the Treaty). These laws are subject to change, possibly on a retroactive basis. This section is further based in part on the representations of the Depositary and assumes that each obligation in the Deposit Agreement and any related agreement will be performed in accordance with its terms.

For purposes of the Treaty and the estate and gift tax Convention (the Estate Tax Convention), and for US federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the company s ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs and ADRs for ordinary shares generally will not be subject to US federal income tax or to UK taxation other than stamp duty or stamp duty reserve tax, as described below.

Investors should consult their own tax adviser regarding the US federal, state and local, the UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Treaty.

Taxation of dividends

UK taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the company, including dividends paid to US holders. A shareholder that is a company resident for tax purposes in the UK or trading in the UK through a permanent establishment generally will not be taxable in the UK on a dividend it receives from the company. A shareholder who is an individual resident for tax purposes in the UK is subject to UK tax but entitled to a tax credit on cash dividends paid on ordinary shares or ADSs of the company equal to one-ninth of the cash dividend.

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Additional information for shareholders

US federal income taxation

A US holder is subject to US federal income taxation on the gross amount of any dividend paid by the company out of its current or accumulated earnings and profits (as determined for US federal income tax purposes). Dividends paid to a non-corporate US holder in taxable years beginning before 1 January 2011 that constitute qualified dividend income will be taxable to the holder at a maximum tax rate of 15%, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the company with respect to the shares or ADSs will generally be qualified dividend income.

As noted above in UK taxation, a US holder will not be subject to UK withholding tax. A US holder will include in gross income for US federal income tax purposes the amount of the dividend actually received from the company and the receipt of a dividend will not entitle the US holder to a foreign tax credit.

For US federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depositary, in the case of ADSs, actually or constructively receives the dividend, and will not be eligible for the dividends-received deduction generally allowed to US corporations in respect of dividends received from other US corporations. Dividends will be income from sources outside the US, and generally will be passive category income or, in the case of certain US holders, general category income, each of which is treated separately for purposes of computing a US holder s foreign tax credit limitation.

The amount of the dividend distribution on the ordinary shares or ADSs that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/US dollar rate on the date the dividend distribution is includible in income, regardless of whether the payment is in fact converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is includible in income to the date the payment is converted into US dollars will be treated as ordinary income or loss and will not be eligible for the 15% tax rate on qualified dividend income. The gain or loss generally will be income or loss from sources within the US for foreign tax credit limitation purposes.

Distributions in excess of the company s earnings and profits, as determined for US federal income tax purposes, will be treated as a return of capital to the extent of the US holder s basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described in Taxation of capital gains US federal income taxation.

In addition, the taxation of dividends may be subject to the rules for passive foreign investment companies, described below under Capital Gains US federal income taxation . Distributions made by a PFIC do not constitute qualified dividend income and are not eligible for the 15% tax rate.

Taxation of capital gains

UK taxation

A US holder may be liable for both UK and US tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (i) a citizen of the US resident or ordinarily resident in the UK, (ii) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK or (iii) a citizen of the US or a corporation that carries on a trade or profession or vocation in the UK through a branch or agency or, in respect of corporations for accounting periods beginning on or after 1 January 2003, through a permanent establishment, and that have used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment. However, such persons may be entitled to a tax credit against their US federal income tax liability for the amount of UK capital gains tax or UK corporation tax on chargeable gains (as the case may be) that is paid in respect of such gain.

Under the Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence of the relevant holder as determined under both the laws of the UK and the US and as required by the terms of the Treaty.

Under the Treaty, individuals who are residents of either the UK or the US and who have been residents of the other jurisdiction (the US or the UK, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the company not only in the jurisdiction of which the holder is resident at the time of the disposition but also in the other jurisdiction.

US federal income taxation

A US holder that sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for US federal income tax purposes equal to the difference between the US dollar value of the amount realized and the holder s tax basis, determined in US dollars, in the ordinary shares or ADSs. Capital gain of a non-corporate US holder that is recognized in taxable years beginning before 1 January 2011 is generally taxed at a maximum rate of 15% if the holder s holding period for such ordinary shares or ADSs exceeds one year. The gain or loss will generally be income or loss from sources within the US for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

We do not believe that ordinary shares or ADSs will be treated as stock of a passive foreign investment company, or PFIC, for US federal income tax purposes, but this conclusion is a factual determination that is made annually and thus is subject to change. If we are treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to ordinary shares or ADSs, gain realized on the sale or other disposition of ordinary shares or ADSs would in general not be treated as capital gain. Instead a US holder would be treated as if he or she had realized such gain rateably over the holding period for ordinary shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, in addition to which an interest charge in respect of the tax attributable to each such year would apply. Certain excess distributions would be similarly treated if we were treated as a PFIC.

Additional tax considerations

Proposed scrip dividend programme

Subject to shareholder approval at the Annual General Meeting on 15 April, the company is planning to introduce an optional scrip dividend programme, wherein holders of ordinary shares or ADSs may elect to receive their dividends in the form of new fully paid ordinary shares or ADSs of the company, instead of cash. Please consult your tax adviser for the consequences to you.

UK inheritance tax

The Estate Tax Convention applies to inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to UK inheritance tax on the individual s death or on transfer during the individual s lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK used for the performance of independent personal services. In the exceptional case where ADSs are subject both to inheritance tax and to US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

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Additional information for shareholders

UK stamp duty and stamp duty reserve tax
The statements below relate to what is understood to be the current practice of HM Revenue & Customs in the UK under existing law.

Provided that any instrument of transfer is not executed in the UK and remains at all times outside the UK and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of £5 per £1,000 (or part, unless the stamp duty is less than £5, when no stamp duty is charged), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser.

A subsequent transfer of ordinary shares to the Depositary s nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer. An ADR holder electing to receive ADSs instead of a cash dividend will be responsible for the stamp duty reserve tax due on issue of shares to the Depositary s nominee and calculated at the rate of 1.5% on the issue price of the shares. It is understood that HM Revenue & Customs, practice is to calculate the issue price by reference to the total cash receipt to which a US holder would have been entitled had the election to receive ADSs instead of a cash dividend not been made. ADR holders electing to receive ADSs instead of the cash dividend authorize the Depositary to sell sufficient shares to cover this liability.

Documents on display
BP s Annual Report and Accounts is also available online at *www.bp.com/annualreport*. Shareholders may obtain a hard copy of BP s complete audited financial statements, free of charge, by contacting BP Distribution Services at +44 (0)870 241 3269 or through an email request addressed to *bpdistributionservices@bp.com* (UK and Rest of World) or from Precision IR at + 1 888 301 2505 or through an email request addressed to *bpreports@precisionir.com* (US and Canada).

The company is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, the company files its Annual Report on Form 20-F and other related documents with the SEC. It is possible to read and copy documents that have been filed with the SEC at the SEC s public reference room located at 100 F Street NE, Washington, DC 20549, US. You may also call the SEC at +1 800-SEC-0330 or log on to *www.sec.gov*. In addition, BP s SEC filings are available to the public at the SEC s website *www.sec.gov*. BP discloses on its website at *www.bp.com/NYSEcorporategovernancerules*, and in its Annual Report on Form 20-F (Item 16G) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

Controls and procedures

Evaluation of disclosure controls and procedures

The company maintains disclosure controls and procedures as such term is defined in Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed in reports the company
files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including the company s group chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, our management, including the group chief executive and chief financial officer, recognize that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. Further, in the design and evaluation of our disclosure controls and procedures our management necessarily was required to apply its judgement in evaluating the cost-benefit relationship of possible controls and procedures. Also, we have investments in certain unconsolidated entities. As we do not control these entities, our disclosure controls and procedures with respect to such entities are necessarily substantially more limited than those we maintain with respect to our consolidated subsidiaries. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. The company s disclosure controls and procedures have been designed to meet, and management believe that they meet, reasonable assurance standards.

The company s management, with the participation of the company s group chief executive and chief financial officer, has evaluated the effectiveness of the company s disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the group chief executive and chief financial officer have concluded that the company s disclosure controls and procedures were effective at a reasonable assurance level.

Changes in internal controls over financial reporting

There were no changes in the group s internal controls over financial reporting that occurred during the period covered by the Form 20-F that have materially affected or are reasonably likely to materially affect, our internal controls over financial reporting.

Management s report on internal control over financial reporting

Management of BP is responsible for establishing and maintaining adequate internal control over financial reporting. BP s internal control over financial reporting is a process designed under the supervision of the principal executive and principal financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of BP s financial statements for external reporting purposes in accordance with IFRS.

As of the end of the 2009 fiscal year, management conducted an assessment of the effectiveness of internal control over financial reporting in accordance with the Internal Control Revised Guidance for Directors on the Combined Code (Turnbull). Based on this assessment, management has determined that BP s internal control over financial reporting as of 31 December 2009 was effective.

The company s internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of BP; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of BP s assets that could have a material effect on our financial statements.

Additional information for shareholders

BP s internal control over financial reporting as of 31 December 2009 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report appearing on page 108 of this *Annual Report on Form 20-F 2009*.

Code of ethics

The company has adopted a code of ethics for its group chief executive, chief financial officer, deputy chief financial officer, group controller, general auditors and chief accounting officer as required by the provisions of Section 406 of the Sarbanes-Oxley Act of 2002 and the rules issued by the SEC. There have been no waivers from the code of ethics relating to any officers. The code has been amended to reflect changes to the titles and posts of certain senior officers. The amended code of ethics has been filed as an exhibit to our Annual Report on Form 20-F.

In June 2005, BP published a code of conduct, which is applicable to all employees.

Principal accountants fees and services

The audit committee has established policies and procedures for the engagement of the independent registered public accounting firm, Ernst & Young LLP, to render audit and certain assurance and tax services. The policies provide for pre-approval by the audit committee of specifically defined audit, audit-related, tax and other services that are not prohibited by regulatory or other professional requirements. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young relative to that of other potential service providers. These services are for a fixed term.

Under the policy, pre-approval is given for specific services within the following categories: advice on accounting, auditing and financial reporting matters; internal accounting and risk management control reviews (excluding any services relating to information systems design and implementation); non-statutory audit; project assurance and advice on business and accounting process improvement (excluding any services relating to information systems design and implementation relating to BP s financial statements or accounting records); due diligence in connection with acquisitions, disposals and joint ventures (excluding valuation or involvement in prospective financial information); income tax and indirect tax compliance and advisory services; and employee tax services (excluding tax services that could impair independence); provision of, or access to, Ernst & Young publications, workshops, seminars and other training materials; provision of reports from data gathered on non-financial policies and information; and assistance with understanding non-financial regulatory requirements. Additionally, any proposed service not included in the pre-approved services, must be approved in advance prior to commencement of the engagement. The audit committee has delegated to the chairman of the audit committee authority to approve permitted services provided that the chairman reports any decisions to the committee at its next scheduled meeting.

The audit committee evaluates the performance of the auditors each year. The audit fees payable to Ernst & Young are reviewed by the committee in the context of other global companies for cost effectiveness. The committee keeps under review the scope and results of audit work and the independence and objectivity of the auditors. External regulation and BP policy requires the auditors to rotate their lead audit partner every five years.

(*See Financial statements Note 14 on page 134 and Audit committee report on page 70 for details of audit fees.*)

Corporate governance practices

In the US, BP ADSs are listed on the New York Stock Exchange (NYSE). The significant differences between BP s corporate governance practices as a UK company and those required by NYSE listing standards for US companies are listed as follows:

Independence

BP has adopted a robust set of board governance principles, which reflect the UK s Combined Code and its principles-based approach to corporate governance. As such, the way in which BP makes determinations of directors independence differs from the NYSE rules.

BP s board governance principles require that all non-executive directors be determined by the board to be independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement . The BP board has determined that, in its judgement, all of the non-executive directors are independent. In doing so, however, the board did not explicitly take into consideration the independence requirements outlined in the NYSE s listing standards.

Committees

BP has a number of board committees which are broadly comparable in purpose and composition to those required by NYSE rules for domestic US companies. For instance, BP has a chairman s (rather than executive) committee, nomination (rather than nominating/corporate governance) committee and remuneration (rather than compensation) committee. BP also has an audit committee, which NYSE rules require for both US companies and foreign private issuers. These committees are composed solely of non-executive directors whom the board has determined to be independent, in the manner described above.

The BP board governance principles prescribe the composition, main tasks and requirements of each of the committees (*see the board committees on pages 70-76*). BP has not, therefore, adopted separate charters for each committee.

Under US securities law and the listing standards of the NYSE, BP is required to have an audit committee which satisfies the requirements of Rule 10A-3 under the Exchange Act and Section 303A.06 of the NYSE Listed Company Manual. BP s audit committee complies with these requirements.

One of the NYSE s additional requirements for the audit committee states that at least one member of the audit committee is to have accounting or related financial management expertise . As reported in *BP Annual Report on Form 20-F 2008*, the board determined that Douglas Flint possessed such expertise and also possesses the financial and audit committee experiences set forth in both the Combined Code and SEC rules (*see Audit committee report on page 70*).

Shareholder approval of equity compensation plans

The NYSE rules for US companies require that shareholders must be given the opportunity to vote on all equity-compensation plans and material revisions to those plans. BP complies with UK requirements which are similar to the NYSE rules. The board, however, does not explicitly take into consideration the NYSE s detailed definition of what are considered material revisions .

Code of ethics

The NYSE rules require that US companies adopt and disclose a code of business conduct and ethics for directors, officers and employees. BP has adopted a code of conduct, which applies to all employees, and has board governance principles which address the conduct of directors. In addition BP has adopted a code of ethics for senior financial officers as required by the SEC. The code has been amended to reflect changes to the titles and posts of certain senior officers. BP considers that these codes and policies address the matters specified in the NYSE rules for US companies.

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Additional information for shareholders

Purchases of equity securities by the issuer and affiliated purchasers

At the AGM on 16 April 2009, authorization was given to repurchase up to 1.8 billion ordinary shares in the period to the next AGM in 2010 or
15 July 2010, the latest date by which an AGM must be held. This authorization is renewed annually at the AGM. No repurchases of shares were made in the period 1 January 2009 to 18 February 2010.

The following table provides details of share purchases made by ESOP trusts.

	Total number of shares purchased	$ Average price paid per share	Total number of shares purchased as part of publicly announced programmes	Maximum number of shares that may yet be purchased under the programme[a]
2009				
January				
February	**126**	**7.48**		
March	**118**	**6.35**		
April				
May				
June	**553**	**7.46**		
July	**1,090,018**	**8.35**		
August	**54**	**8.16**		
September	**134**	**8.36**		
October	**713**	**8.42**		
November	**1,265,242**	**11.41**		
December	**58**	**8.82**		
2010				
January	**51**	**10.36**		
February (to 18 February)	**144,523**	**11.41**		

[a] No shares were repurchased pursuant to a publicly announced plan. Transactions represent the purchase of ordinary shares by ESOP trusts to satisfy future requirements of employee share schemes.

Fees and charges payable by a holder of ADSs

The Depositary collects fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of the distributable property to pay the fees.

The charges of the Depositary payable by investors are as follows:

Type of service	Depositary actions	Fee
Depositing or substituting the	Issuance of ADSs against the deposit of shares, including	$5.00 per 100 ADSs (or portion thereof)

underlying shares	deposits and issuances in respect of: Share distributions, stock splits, rights, merger Exchange of securities or other transactions or event or other distribution affecting the ADSs or deposited securities	evidenced by the new ADSs delivered
Selling or exercising rights	Distribution or sale of securities, the fee being in an amount equal to the fee for the execution and delivery of ADSs which would have been charged as a result of the deposit of such securities	$5.00 per 100 ADSs (or portion thereof)
Withdrawing an underlying share	Acceptance of ADSs surrendered for withdrawal of deposited securities	$5.00 for each 100 ADSs (or portion thereof) evidenced by the ADSs surrendered
Expenses of the Depositary	Expenses incurred on behalf of holders in connection with: Stock transfer or other taxes and governmental charges Cable, telex, electronic and facsimile transmission/delivery Transfer or registration fees, if applicable, for the registration of transfers of underlying shares Expenses of the Depositary in connection with the conversion of foreign currency into US dollars (which are paid out of such foreign currency)	Expenses payable at the sole discretion of the Depositary by billing holders or by deducting charges from one or by deducting charges from one or more cash dividends or other cash distributions

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Additional information for shareholders

Fees and payments made by the Depositary to the issuer
The Depositary has agreed to reimburse certain company expenses related to the company s ADS programme and incurred by the company in connection with the programme. The Depositary reimbursed to the company, or paid amounts on the company s behalf to third parties, or waived its fees and expenses, of $4,565,411 for the year ended 31 December 2009.

The table below sets forth the types of expenses that the Depositary has agreed to reimburse, and the invoices relating to the year ended 31 December 2009 that were reimbursed:

Category of expense reimbursed to the company	Amount reimbursed for the year ended 31 December 2009
NYSE listing fees[a]	$500,000
Printing costs in connection with US shareholder communications and AGM related expenses in connection with the ADR programme	$140,226
Total	$640,226

[a] During 2009 the company received a payment of $500,000 from the Depositary in respect of NYSE listing fee for 2008.

The Depositary has also agreed to waive fees for standard costs associated with the administration of the ADS programme and has paid certain expenses directly to third parties on behalf of the company. The table below sets forth those expenses that the Depositary waived or paid directly to third parties relating to the year ended 31 December 2009:

Category of expense waived or paid directly to third parties[a]	Amount reimbursed for the year ended 31 December 2009
Service fees and out of pocket expenses waived[b]	$2,706,973
Broker reimbursements[c]	$1,070,408
Other third-party mailing costs[d]	$132,435
Transfer agency fees in Canada[e]	$10,441
Other third-party expenses paid directly	$4,928
Total	$3,925,185

a

In addition to the reimbursed and waived fees for the year ended 31 December 2009, the Depositary also reimbursed, waived or paid directly to third parties $2,656,148 that related to the year ended 31 December 2008.

[b] Includes fees in relation to transfer agent costs and operation of BP Direct Access Plan by JPMorgan Chase.

[c] Broker reimbursements are fees payable to Broadridge and other service providers for the distribution of hard copy material to ADR beneficial holders in the Depositary Trust Company. Corporate materials include information related to shareholders meetings and related voting instructions. These fees are SEC approved.

[d] Reimbursement of fees to UPS Mail innovations, Precision IR and Bank of New York Mellon for distribution of hard copy materials to ADR beneficial holders and proxy solicitation.

[e] Fees payable to CIBC as co-transfer agent for Canadian ADR holders.

Under certain circumstances, including removal of the Depositary or termination of the ADR programme by the company, the company is required to repay the Depositary amounts reimbursed and/or expenses paid to or on behalf of the company during the 12-month period prior to notice of removal or termination.

Called-up share capital

Details of the allotted, called up and fully paid share capital at 31 December 2009 are set out in Financial statements Note 36 on page 165.

At the AGM on 16 April 2009, authorization was given to the directors to allot shares up to an aggregate nominal amount equal to $1,561 million. Authority was also given to the directors to allot shares for cash and to dispose of treasury shares, other than by way of rights issue, up to a maximum of $234 million, without having to offer such shares to existing shareholders. These authorities are given for the period until the next AGM in 2010 or 15 July 2010, whichever is the earlier. These authorities are renewed annually at the AGM.

Administration

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payments, the dividend reinvestment plan or the ADS direct access plan, or to change the way you receive your company documents (such as the Annual Report and Accounts, Annual Review and Notice of Meeting) please contact the BP Registrar or ADS Depositary.

UK Registrar s Office
The BP Registrar, Equiniti
Aspect House, Spencer Road, Lancing, West Sussex BN99 6DA
Freephone in UK 0800 701107; Tel +44 (0)121 415 7005
Textphone 0871 384 2255; Fax +44 (0)871 384 2100

Please note that any numbers quoted with the prefix 0871 will be charged at 8p per minute from a BT landline. Other network providers costs may vary.

US ADS Depositary
JPMorgan Chase Bank, N.A.
PO Box 64504, St. Paul, MN 55164-0504
Toll-free in US and Canada +1 877 638 5672; Tel +1 651 306 4383
For the hearing impaired +1 651 453 2133

Annual general meeting

The 2010 AGM will be held on Thursday, 15 April 2010 at 11.30 a.m. at ExCeL London, One Western Gateway, Royal Victoria Dock, London E16 1XL. A separate notice convening the meeting is distributed to shareholders, which includes an explanation of the items of business to be considered at the meeting.

All resolutions of which notice has been given will be decided on a poll.

Ernst & Young LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in *Notice of BP Annual General Meeting 2010.*

By order of the board
David J Jackson
Secretary

26 February 2010
BP p.l.c.
Registered in England and Wales No. 102498

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Additional information for shareholders

Exhibits

The following documents are filed as part of this annual report:

Exhibit 1.	Memorandum and Articles of Association of BP p.l.c.*
Exhibit 4.1	The BP Executive Directors Incentive Plan**
Exhibit 4.2	Medium Term Performance Plan***
Exhibit 4.3	Deferred Annual Bonus Plan***
Exhibit 4.4	Performance Share Plan***
Exhibit 4.5	Director s Service Contract and Secondment Agreement for RW Dudley
Exhibit 4.6	Amended Director s Service Contract and Secondment Agreement for Dr BE Grote****
Exhibit 7.	Computation of Ratio of Earnings to Fixed Charges (Unaudited)
Exhibit 8.	Subsidiaries (included as Note 43 to the Financial Statements)
Exhibit 11.	Code of Ethics
Exhibit 12.	Rule 13a 14(a) Certifications
Exhibit 13.	Rule 13a 14(b) Certifications#

* Incorporated by reference to the company s Report on Form 6-K filed on 22 May 2008 (File No. 001 06262)

** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2004.

*** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2008.

**** The original Director s Service Contract and Secondment Agreement for Dr BE Grote is incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2002.

\# Furnished only.

Included only in the annual report filed in the Securities and Exchange Commission EDGAR system.

The total amount of long-term securities of the Registrant and its subsidiaries authorized under any one instrument does not exceed 10% of the total assets of BP p.l.c. and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any or all such instruments to the Securities and Exchange Commission upon request.

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Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of BP p.l.c.

We have audited the accompanying group balance sheets of BP p.l.c. as of 31 December 2009 and 2008, and the related group income statement, group cash flow statement, group statement of comprehensive income and group statement of changes in equity, for each of the three years in the period ended 31 December 2009. These financial statements are the responsibility of the company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the group financial position of BP p.l.c. at
31 December 2009 and 2008, and the group results of operations and cash flows for each of the three years in the period ended 31 December 2009, in accordance with International Financial Reporting Standards as adopted by the European Union and International Financial Reporting Standards as issued by the International Accounting Standards Board.

As discussed in Note 1 to the consolidated financial statements, the company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of BP p.l.c. s internal control over financial reporting as of 31 December 2009, based on criteria established in the Internal Control Revised Guidance for Directors on the Combined Code (Turnbull) as issued by the Institute of Chartered Accountants in England and Wales (the Turnbull criteria) and our report dated 26 February 2010 expressed an unqualified opinion thereon.

/s/ERNST & YOUNG LLP

Ernst & Young LLP
London, England
26 February 2010

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of BP p.l.c.

We have audited BP p.l.c. s internal control over financial reporting as of 31 December 2009, based on criteria established in Internal
Control-Revised Guidance for Directors on the Combined Code (Turnbull) as issued by the Institute of Chartered Accountants in England and Wales (the Turnbull criteria). BP p.l.c. s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s report on internal control over financial reporting on page 101. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, BP p.l.c. maintained, in all material respects, effective internal control over financial reporting as of 31 December 2009, based on the Turnbull criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the group balance sheets of BP p.l.c. as of 31 December 2009 and 2008, and the related group income statement, group cash flow statement, group statement of comprehensive income and group statement of changes in equity, for each of the three years in the period ended 31 December 2009, and our report dated 26 February 2010 expressed an unqualified opinion thereon.

/s/ERNST & YOUNG LLP

Ernst & Young LLP
London, England
26 February 2010

Consolidated financial statements of the BP group

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 26 February 2010 with respect to the group financial statements of BP p.l.c., and the effectiveness of internal control over financial reporting of BP p.l.c., included in this Annual Report (Form 20-F) for the year ended 31 December 2009 in the following registration statements:

Registration Statement on Form F-3 (File No. 333-155798) of BP p.l.c.;

Registration Statement on Form F-3 (File No. 333-157906) of BP Capital Markets p.l.c. and BP p.l.c.; and

Registration Statements on Form S-8 (File Nos. 333-149778, 333-79399, 333-67206, 333-102583, 333-103924, 333-123482, 333-123483, 333-131583, 333-146868, 333-146870, 333-146873, 333-131584 and 333-132619) of BP p.l.c.

/s/ERNST & YOUNG LLP

Ernst & Young LLP

London, England

5 March 2010

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Consolidated financial statements of the BP group

Group income statement

For the year ended 31 December				$ million
	Note	**2009**	2008	2007
Sales and other operating revenues	4	**239,272**	361,143	284,365
Earnings from jointly controlled entities after interest and tax		**1,286**	3,023	3,135
Earnings from associates after interest and tax		**2,615**	798	697
Interest and other income	5	**792**	736	754
Gains on sale of businesses and fixed assets	3	**2,173**	1,353	2,487
Total revenues and other income		**246,138**	367,053	291,438
Purchases		**163,772**	266,982	200,766
Production and manufacturing expenses	6	**23,202**	26,756	24,225
Production and similar taxes	6	**3,752**	8,953	5,703
Depreciation, depletion and amortization	7	**12,106**	10,985	10,579
Impairment and losses on sale of businesses and fixed assets	3	**2,333**	1,733	1,679
Exploration expense	13	**1,116**	882	756
Distribution and administration expenses	9	**14,038**	15,412	15,371
Fair value (gain) loss on embedded derivatives	31	**(607)**	111	7
Profit before interest and taxation		**26,426**	35,239	32,352
Finance costs	15	**1,110**	1,547	1,393
Net finance expense (income) relating to pensions and other post-retirement benefits	35	**192**	(591)	(652)
Profit before taxation		**25,124**	34,283	31,611
Taxation	16	**8,365**	12,617	10,442
Profit for the year		**16,759**	21,666	21,169
Attributable to				
BP shareholders		**16,578**	21,157	20,845
Minority interest		**181**	509	324
		16,759	21,666	21,169
Earnings per share cents				
Profit for the year attributable to BP shareholders				
Basic	18	**88.49**	112.59	108.76
Diluted	18	**87.54**	111.56	107.84

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Consolidated financial statements of the BP group

Group statement of comprehensive income

For the year ended 31 December	Note	2009	2008	$ million 2007
Profit for the year		**16,759**	21,666	21,169
Currency translation differences		**1,826**	(4,362)	1,887
Exchange gains on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	3	**(27)**		(147)
Actuarial (loss) gain relating to pensions and other post-retirement benefits	35	**(682)**	(8,430)	1,717
Available-for-sale investments marked to market		**705**	(994)	200
Available-for-sale investments recycled to the income statement		**2**	526	(91)
Cash flow hedges marked to market		**652**	(1,173)	155
Cash flow hedges recycled to the income statement		**366**	45	(74)
Cash flow hedges recycled to the balance sheet		**136**	(38)	(40)
Taxation	37	**525**	2,946	(276)
Other comprehensive income		**3,503**	(11,480)	3,331
Total comprehensive income		**20,262**	10,186	24,500
Attributable to				
BP shareholders		**20,137**	9,752	24,152
Minority interest		**125**	434	348
		20,262	10,186	24,500

Group statement of changes in equity

	2009			2008				$ million 2007	
	BP shareholders equity	**Minority interest**	**Total equity**	BP shareholders equity	Minority interest	Total equity	BP shareholders' equity	Minority interest	Total equity
At 1 January	**91,303**	**806**	**92,109**	93,690	962	94,652	84,624	841	85,465
Total comprehensive income	**20,137**	**125**	**20,262**	9,752	434	10,186	24,152	348	24,500
Dividends	**(10,483)**	**(416)**	**(10,899)**	(10,342)	(425)	(10,767)	(8,106)	(227)	(8,333)

Repurchase of ordinary share capital				(2,414)		(2,414)	(7,997)		(7,997)
Share-based payments (net of tax)	**721**		**721**	617		617	1,017		1,017
Changes in associates equity	**(43)**		**(43)**						
Minority interest buyout	**(22)**	**(15)**	**(37)**		(165)	(165)			
At 31 December	**101,613**	**500**	**102,113**	91,303	806	92,109	93,690	962	94,652

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Consolidated financial statements of the BP group

Group balance sheet

At 31 December	Note	2009	$ million 2008
Non-current assets			
Property, plant and equipment	19	**108,275**	103,200
Goodwill	20	**8,620**	9,878
Intangible assets	21	**11,548**	10,260
Investments in jointly controlled entities	22	**15,296**	23,826
Investments in associates	23	**12,963**	4,000
Other investments	25	**1,567**	855
Fixed assets		**158,269**	152,019
Loans		**1,039**	995
Other receivables	27	**1,729**	710
Derivative financial instruments	31	**3,965**	5,054
Prepayments		**1,407**	1,338
Deferred tax assets	16	**516**	
Defined benefit pension plan surpluses	35	**1,390**	1,738
		168,315	161,854
Current assets			
Loans		**249**	168
Inventories	26	**22,605**	16,821
Trade and other receivables	27	**29,531**	29,261
Derivative financial instruments	31	**4,967**	8,510
Prepayments		**1,753**	3,050
Current tax receivable		**209**	377
Cash and cash equivalents	28	**8,339**	8,197
		67,653	66,384
Total assets		**235,968**	228,238
Current liabilities			
Trade and other payables	30	**35,204**	33,644
Derivative financial instruments	31	**4,681**	8,977
Accruals		**6,202**	6,743
Finance debt	32	**9,109**	15,740
Current tax payable		**2,464**	3,144
Provisions	34	**1,660**	1,545
		59,320	69,793

Non-current liabilities			
Other payables	30	**3,198**	3,080
Derivative financial instruments	31	**3,474**	6,271
Accruals		**703**	784
Finance debt	32	**25,518**	17,464
Deferred tax liabilities	16	**18,662**	16,198
Provisions	34	**12,970**	12,108
Defined benefit pension plan and other post-retirement benefit plan deficits	35	**10,010**	10,431
		74,535	66,336
Total liabilities		**133,855**	136,129
Net assets		**102,113**	92,109
Equity			
Share capital	36	**5,179**	5,176
Reserves		**96,434**	86,127
BP shareholders equity	37	**101,613**	91,303
Minority interest	37	**500**	806
Total equity	37	**102,113**	92,109

C-H Svanberg Chairman
Dr A B Hayward Group Chief Executive
26 February 2010

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Consolidated financial statements of the BP group

Group cash flow statement

For the year ended 31 December				$ million
	Note	**2009**	2008	2007
Operating activities				
Profit before taxation		**25,124**	34,283	31,611
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	13	**593**	385	347
Depreciation, depletion and amortization	7	**12,106**	10,985	10,579
Impairment and (gain) loss on sale of businesses and fixed assets	3	**160**	380	(808)
Earnings from jointly controlled entities and associates		**(3,901)**	(3,821)	(3,832)
Dividends received from jointly controlled entities and associates		**3,003**	3,728	2,473
Interest receivable		**(258)**	(407)	(489)
Interest received		**203**	385	500
Finance costs	15	**1,110**	1,547	1,393
Interest paid		**(909)**	(1,291)	(1,363)
Net finance expense (income) relating to pensions and other post-retirement benefits	35	**192**	(591)	(652)
Share-based payments		**450**	459	420
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans		**(887)**	(173)	(404)
Net charge for provisions, less payments		**650**	(298)	(92)
(Increase) decrease in inventories		**(5,363)**	9,010	(7,255)
Decrease in other current and non-current assets		**7,595**	2,439	5,210
Decrease in other current and non-current liabilities		**(5,828)**	(6,101)	(3,857)
Income taxes paid		**(6,324)**	(12,824)	(9,072)
Net cash provided by operating activities		**27,716**	38,095	24,709
Investing activities				
Capital expenditure		**(20,650)**	(22,658)	(17,830)
Acquisitions, net of cash acquired		**1**	(395)	(1,225)
Investment in jointly controlled entities		**(578)**	(1,009)	(428)
Investment in associates		**(164)**	(81)	(187)
Proceeds from disposals of fixed assets	3	**1,715**	918	1,749
Proceeds from disposals of businesses, net of cash disposed	3	**966**	11	2,518
Proceeds from loan repayments		**530**	647	192
Other		**47**	(200)	374
Net cash used in investing activities		**(18,133)**	(22,767)	(14,837)
Financing activities				
Net issue (repurchase) of shares		**207**	(2,567)	(7,113)
Proceeds from long-term financing		**11,567**	7,961	8,109
Repayments of long-term financing		**(6,021)**	(3,821)	(3,192)

Net increase (decrease) in short-term debt		**(4,405)**	(1,315)	1,494
Dividends paid				
BP shareholders	17	**(10,483)**	(10,342)	(8,106)
Minority interest		**(416)**	(425)	(227)
Net cash used in financing activities		**(9,551)**	(10,509)	(9,035)
Currency translation differences relating to cash and cash equivalents		**110**	(184)	135
Increase in cash and cash equivalents		**142**	4,635	972
Cash and cash equivalents at beginning of year		**8,197**	3,562	2,590
Cash and cash equivalents at end of year		**8,339**	8,197	3,562

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Notes on financial statements

1. Significant accounting policies

Authorization of financial statements and statement of compliance with International Financial Reporting Standards

The consolidated financial statements of the BP group for the year ended 31 December 2009 were approved and signed by the chairman and group chief executive on 26 February 2010 having been duly authorized to do so by the board of directors. BP p.l.c. is a public limited company incorporated and domiciled in England and Wales. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and IFRS as adopted by the European Union (EU). IFRS as adopted by the EU differs in certain respects from IFRS as issued by the IASB, however, the differences have no impact on the group s consolidated financial statements for the years presented. The significant accounting policies of the group are set out below.

Basis of preparation

The consolidated financial statements have been prepared in accordance with IFRS and International Financial Reporting Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2009, or issued and early adopted. The standards and interpretations adopted in the year are described further on page 121.

The accounting policies that follow have been consistently applied to all years presented. The group balance sheet as at 1 January 2008 is not presented as it is not affected by the retrospective adoption of any new accounting policies during the year, nor any other retrospective restatements or reclassifications.

The consolidated financial statements are presented in US dollars and all values are rounded to the nearest million dollars ($ million), except where otherwise indicated.

For further information regarding the key judgements and estimates made by management in applying the group s accounting policies, refer to Critical accounting policies on pages 90 to 92, which forms part of these financial statements.

Basis of consolidation

The group financial statements consolidate the financial statements of BP p.l.c. and the entities it controls (its subsidiaries) drawn up to 31 December each year. Control comprises the power to govern the financial and operating policies of the investee so as to obtain benefit from its activities and is achieved through direct and indirect ownership of voting rights; currently exercisable or convertible potential voting rights; or by way of contractual agreement. Subsidiaries are consolidated from the date of their acquisition, being the date on which the group obtains control, and continue to be consolidated until the date that such control ceases. The financial statements of subsidiaries are prepared for the same reporting year as the parent company, using consistent accounting policies. All intercompany balances and transactions, including unrealized profits arising from intragroup transactions, have been eliminated in full. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred. Minority interests represent the portion of profit or loss and net assets in subsidiaries that is not held by the group.

Segmental reporting

The group s operating segments are established on the basis of those components of the group that are evaluated regularly by the chief operating decision maker in deciding how to allocate resources and in assessing performance. The accounting policies of the operating segments are the same as the group s accounting policies described in this note, except that IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker. For BP, this measure of profit or loss is replacement cost profit before interest and tax which reflects the replacement cost of supplies by excluding from profit inventory holding gains and losses. Replacement cost profit for the group is not a recognized measure under generally accepted accounting practice (GAAP). For further information see Note 4.

Interests in joint ventures

A joint venture is a contractual arrangement whereby two or more parties (venturers) undertake an economic activity that is subject to joint control. Joint control exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the venturers. A jointly controlled entity is a joint venture that involves the establishment of a company, partnership or other entity to engage in economic activity that the group jointly controls with its fellow venturers.

The results, assets and liabilities of a jointly controlled entity are incorporated in these financial statements using the equity method of accounting. Under the equity method, the investment in a jointly controlled entity is carried in the balance sheet at cost, plus post-acquisition changes in the group s share of net assets of the jointly controlled entity, less distributions received and less any impairment in value of the investment. Loans advanced to jointly controlled entities are also included in the investment on the group balance sheet. The group income statement reflects the group s share of the results after tax of the jointly controlled entity.

Financial statements of jointly controlled entities are prepared for the same reporting year as the group. Where necessary, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group.

Unrealized gains on transactions between the group and its jointly controlled entities are eliminated to the extent of the group s interest in the jointly controlled entities. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The group assesses investments in jointly controlled entities for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If any such indication of impairment exists, the carrying amount of the investment is compared with its recoverable amount, being the higher of its fair value less costs to sell and value in use. Where the carrying amount exceeds the recoverable amount, the investment is written down to its recoverable amount.

The group ceases to use the equity method of accounting on the date from which it no longer has joint control or significant influence over the joint venture, or when the interest becomes held for sale.

Certain of the group s activities, particularly in the Exploration and Production segment, are conducted through joint ventures where the venturers have a direct ownership interest in, and jointly control, the assets of the venture. BP recognizes, on a line-by-line basis in the consolidated financial statements, its share of the assets, liabilities and expenses of these jointly controlled assets, along with the group s income from the sale of its share of the output and any liabilities and expenses incurred in relation to the venture.

Notes on financial statements

1. Significant accounting policies continued

Interests in associates

An associate is an entity over which the group is in a position to exercise significant influence through participation in the financial and operating policy decisions of the investee, but which is not a subsidiary or a jointly controlled entity. The results, assets and liabilities of an associate are incorporated in these financial statements using the equity method of accounting as described above for jointly controlled entities.

Foreign currency translation

Functional currency is the currency of the primary economic environment in which an entity operates and is normally the currency in which the entity primarily generates and expends cash.

In individual companies, transactions in foreign currencies are initially recorded in the functional currency by applying the rate of exchange ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the rate of exchange ruling at the balance sheet date. Any resulting exchange differences are included in the income statement. Non-monetary assets and liabilities, other than those measured at fair value, are not retranslated subsequent to initial recognition.

In the consolidated financial statements, the assets and liabilities of non-US dollar functional currency subsidiaries, jointly controlled entities and associates, including related goodwill, are translated into US dollars at the rate of exchange ruling at the balance sheet date. The results and cash flows of non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars using average rates of exchange. Exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars are taken to a separate component of equity and reported in the statement of comprehensive income. Exchange gains and losses arising on long-term intragroup foreign currency borrowings used to finance the group s non-US dollar investments are also taken to equity. On disposal of a non-US dollar functional currency subsidiary, jointly controlled entity or associate, the deferred cumulative amount of exchange gains and losses recognized in equity relating to that particular non-US dollar operation is reclassified to the income statement.

Business combinations and goodwill

Business combinations are accounted for using the purchase method of accounting. The cost of an acquisition is measured as the cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange, plus costs directly attributable to the acquisition. The acquired identifiable assets, liabilities and contingent liabilities are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the net fair value of the identifiable assets, liabilities and contingent liabilities acquired is recognized as goodwill. Where the group does not acquire 100% ownership of the acquired company, the interest of minority shareholders is stated at the minority s proportion of the fair values of the assets and liabilities recognized.

At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units expected to benefit from the combination s synergies. For this purpose, cash-generating units are set at one level below a business segment.

Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired. Impairment is determined by assessing the recoverable amount of the cash-generating unit to which the goodwill relates. Where the recoverable amount of the cash-generating unit is less than the carrying amount, an impairment loss is recognized.

The cost of goodwill arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount under UK generally accepted accounting practice.

Goodwill may also arise upon investments in jointly controlled entities and associates, being the surplus of the cost of investment over the group s share of the net fair value of the identifiable assets. Such goodwill is recorded within investments in jointly controlled entities and associates, and any impairment of the investment is included within the earnings from jointly controlled entities and associates.

Non-current assets held for sale

Non-current assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell.

Non-current assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification.

Property, plant and equipment and intangible assets once classified as held for sale are not depreciated. The group ceases to use the equity method of accounting on the date from which an interest in a joint venture or an interest in an associate becomes held for sale.

Intangible assets

Intangible assets, other than goodwill, include expenditure on the exploration for and evaluation of oil and natural gas resources, computer software, patents, licences and trademarks and are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses.

Intangible assets acquired separately from a business are carried initially at cost. The initial cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. An intangible asset acquired as part of a business combination is measured at fair value at the date of acquisition and is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights and its fair value can be measured reliably.

Intangible assets with a finite life are amortized on a straight-line basis over their expected useful lives. For patents, licences and trademarks, expected useful life is the shorter of the duration of the legal agreement and economic useful life, and can range from three to 15 years. Computer software costs have a useful life of three to five years.

The expected useful lives of assets are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying value of intangible assets is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable.

Notes on financial statements

1. Significant accounting policies continued

Oil and natural gas exploration, appraisal and development expenditure

Oil and natural gas exploration, appraisal and development expenditure is accounted for using the principles of the successful efforts method of accounting.

Licence and property acquisition costs

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to property, plant and equipment.

Exploration and appraisal expenditure

Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are initially capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. If potentially commercial quantities of hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an asset.

Costs directly associated with appraisal activity, undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalized as an intangible asset.

All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is approved by management, the relevant expenditure is transferred to property, plant and equipment.

Development expenditure

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including service and unsuccessful development or delineation wells, is capitalized within property, plant and equipment and is depreciated from the commencement of production as described below in the accounting policy for property, plant and equipment.

Property, plant and equipment

Property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning obligation, if any, and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included within property, plant and equipment. Exchanges of assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. The gain or loss on derecognition of the asset given up is recognized in profit or loss.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the group, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. Inspection costs associated with major maintenance programmes are capitalized and amortized over the period to the next inspection. Overhaul costs for major maintenance programmes are expensed as incurred. All other maintenance costs are expensed as incurred.

Oil and natural gas properties, including related pipelines, are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, field development and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the amortization of field development costs takes into account expenditures incurred to date, together with approved future development expenditure required to develop reserves.

Other property, plant and equipment is depreciated on a straight line basis over its expected useful life. The useful lives of the group s other property, plant and equipment are as follows:

Land improvements	15 to 25 years
Buildings	20 to 50 years
Refineries	20 to 30 years
Petrochemicals plants	20 to 30 years
Pipelines	10 to 50 years
Service stations	15 years
Office equipment	3 to 7 years
Fixtures and fittings	5 to 15 years

The expected useful lives of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying value of property, plant and equipment is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable.

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period in which the item is derecognized.

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Notes on financial statements

1. Significant accounting policies continued

Impairment of intangible assets and property, plant and equipment

The group assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, for example, low prices or margins for an extended period or, for oil and gas assets, significant downward revisions of estimated volumes or increases in estimated future development expenditure. If any such indication of impairment exists, the group makes an estimate of the asset s recoverable amount. Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. An asset group s recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset s recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Such reversal is recognized in profit or loss. After such a reversal, the depreciation charge is adjusted in future periods to allocate the asset s revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Financial assets

Financial assets are classified as loans and receivables; available-for-sale financial assets; financial assets at fair value through profit or loss; or as derivatives designated as hedging instruments in an effective hedge, as appropriate. Financial assets include cash and cash equivalents, trade receivables, other receivables, loans, other investments, and derivative financial instruments. The group determines the classification of its financial assets at initial recognition. Financial assets are recognized initially at fair value, normally being the transaction price plus, in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs.

The subsequent measurement of financial assets depends on their classification, as follows:

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired, as well as through the amortization process. This category of financial assets includes trade and other receivables.

Available-for-sale financial assets

Available-for-sale financial assets are those non-derivative financial assets that are not classified as loans and receivables. After initial recognition, available-for-sale financial assets are measured at fair value, with gains or losses recognized within other comprehensive income. Accumulated changes in fair value are recorded as a separate component of equity until the investment is derecognized or impaired.

The fair value of quoted investments is determined by reference to bid prices at the close of business on the balance sheet date. Where there is no active market, fair value is determined using valuation techniques. Where fair value cannot be reliably measured, assets are carried at cost.

Financial assets at fair value through profit or loss

Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category. These assets are carried on the balance sheet at fair value with gains or losses recognized in the income statement.

Derivatives designated as hedging instruments in an effective hedge

Such derivatives are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Impairment of financial assets

The group assesses at each balance sheet date whether a financial asset or group of financial assets is impaired.

Loans and receivables

If there is objective evidence that an impairment loss on loans and receivables carried at amortized cost has been incurred, the amount of the loss is measured as the difference between the asset s carrying amount and the present value of estimated future cash flows discounted at the financial asset s original effective interest rate. The carrying amount of the asset is reduced, with the amount of the loss recognized in the income statement.

Available-for-sale financial assets

If an available-for-sale financial asset is impaired, the cumulative loss previously recognized in equity is transferred to the income statement. Any subsequent recovery in the fair value of the asset is recognized within other comprehensive income.

If there is objective evidence that an impairment loss on an unquoted equity instrument that is carried at cost has been incurred, the amount of the loss is measured as the difference between the asset s carrying amount and the present value of estimated future cash flows discounted at the current market rate of return for a similar financial asset.

Inventories

Inventories, other than inventory held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses. Net realizable value is determined by reference to prices existing at the balance sheet date.

Inventories held for trading purposes are stated at fair value less costs to sell and any changes in net realizable value are recognized in the income statement.

Supplies are valued at cost to the group mainly using the average method or net realizable value, whichever is the lower.

Notes on financial statements

1. Significant accounting policies continued

Financial liabilities

Financial liabilities are classified as financial liabilities at fair value through profit or loss; derivatives designated as hedging instruments in an effective hedge; or as financial liabilities measured at amortized cost, as appropriate. Financial liabilities include trade and other payables, accruals, finance debt and derivative financial instruments. The group determines the classification of its financial liabilities at initial recognition. The measurement of financial liabilities depends on their classification, as follows:

Financial liabilities at fair value through profit or loss

Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category. These liabilities are carried on the balance sheet at fair value with gains or losses recognized in the income statement.

Derivatives designated as hedging instruments in an effective hedge

Such derivatives are carried on the balance sheet at fair value, the treatment of gains and losses arising from revaluation are described below in the accounting policy for derivative financial instruments and hedging activities.

Financial liabilities measured at amortized cost

All other financial liabilities are initially recognized at fair value. For interest-bearing loans and borrowings this is the fair value of the proceeds received net of issue costs associated with the borrowing.

After initial recognition, other financial liabilities are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs, and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized respectively in interest and other revenues and finance costs.

This category of financial liabilities includes trade and other payables and finance debt.

Leases

Finance leases, which transfer to the group substantially all the risks and benefits incidental to ownership of the leased item, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Finance charges are allocated to each period so as to achieve a constant rate of interest on the remaining balance of the liability and are charged directly against income.

Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Operating lease payments are recognized as an expense in the income statement on a straight-line basis over the lease term.

For both finance and operating leases, contingent rents are recognized in the income statement in the period in which they are incurred.

Derivative financial instruments and hedging activities

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices as well as for trading purposes. Such derivative financial instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments as if the contracts were financial instruments, with the exception of contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the group s expected purchase, sale or usage requirements, are accounted for as financial instruments.

Gains or losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

For the purpose of hedge accounting, hedges are classified as:

Fair value hedges when hedging exposure to changes in the fair value of a recognized asset or liability.

Cash flow hedges when hedging exposure to variability in cash flows that is either attributable to a particular risk associated with a recognized asset or liability or a highly probable forecast transaction.

Hedges of a net investment in a foreign operation.

At the inception of a hedge relationship the group formally designates and documents the hedge relationship for which the group wishes to claim hedge accounting, together with the risk management objective and strategy for undertaking the hedge. The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, and how the entity will assess the hedging instrument effectiveness in offsetting the exposure to changes in the hedged item s fair value or cash flows attributable to the hedged item. Such hedges are expected at inception to be highly effective in achieving offsetting changes in fair value or cash flows. Hedges meeting the criteria for hedge accounting are accounted for as follows:

Fair value hedges

The change in fair value of a hedging derivative is recognized in profit or loss. The change in the fair value of the hedged item attributable to the risk being hedged is recorded as part of the carrying value of the hedged item and is also recognized in profit or loss.

The group applies fair value hedge accounting for hedging fixed interest rate risk on borrowings. The gain or loss relating to the effective portion of the interest rate swap is recognized in the income statement within finance costs, offsetting the amortization of the interest on the underlying borrowings.

If the criteria for hedge accounting are no longer met, or if the group revokes the designation, the adjustment to the carrying amount of a hedged item for which the effective interest rate method is used is amortized to profit or loss over the period to maturity.

Cash flow hedges

For cash flow hedges, the effective portion of the gain or loss on the hedging instrument is recognized within other comprehensive income, while the ineffective portion is recognized in profit or loss. Amounts taken to equity are transferred to the income statement when the hedged transaction affects profit or loss. The gain or loss relating to the effective portion of interest rate swaps hedging variable rate borrowings is recognized in the income statement within finance costs.

Where the hedged item is the cost of a non-financial asset or liability, such as a forecast transaction for the purchase of property, plant and equipment, the amounts recognized within other comprehensive income are transferred to the initial carrying amount of the non-financial asset or liability.

If the hedging instrument expires or is sold, terminated or exercised without replacement or rollover, or if its designation as a hedge is revoked, amounts previously recognized within other comprehensive income remain in equity until the forecast transaction occurs and are transferred to the income statement or to the initial carrying amount of a non-financial asset or liability as above. If a forecast transaction is no longer expected to occur, amounts previously recognized in equity are reclassified to the income statement.

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Notes on financial statements

1. Significant accounting policies continued

Hedges of a net investment in a foreign operation

For hedges of a net investment in a foreign operation, the effective portion of the gain or loss on the hedging instrument is recognized within other comprehensive income, while the ineffective portion is recognized in profit or loss. Amounts taken to equity are transferred to the income statement when the foreign operation is sold or partially disposed of.

Embedded derivatives

Derivatives embedded in other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of the host contract. Contracts are assessed for embedded derivatives when the group becomes a party to them, including at the date of a business combination. Embedded derivatives are measured at fair value at each balance sheet date. Any gains or losses arising from changes in fair value are taken directly to the income statement.

Provisions and contingencies

Provisions are recognized when the group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where appropriate, the future cash flow estimates are adjusted to reflect risks specific to the liability.

If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money. Where discounting is used, the increase in the provision due to the passage of time is recognized within finance costs.

Contingent liabilities are possible obligations whose existence will only be confirmed by future events not wholly within the control of the group. Contingent liabilities are not recognized in the financial statements but are disclosed unless the possibility of an outflow of economic resources is considered remote.

Decommissioning

Liabilities for decommissioning costs are recognized when the group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reliable estimate of that liability can be made. Where an obligation exists for a new facility, such as oil and natural gas production or transportation facilities, this will be on construction or installation. An obligation for decommissioning may also crystallize during the period of operation of a facility through a change in legislation or through a decision to terminate operations. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements.

A corresponding item of property, plant and equipment of an amount equivalent to the provision is also recognized. This is subsequently depreciated as part of the asset.

Other than the unwinding discount on the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding item of property, plant and equipment. Such changes include foreign exchange gains and losses arising on the retranslation of the liability into the functional currency of the reporting entity, when it is known that the liability will be settled in a foreign currency.

Environmental expenditures and liabilities

Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future earnings are expensed.

Liabilities for environmental costs are recognized when a clean-up is probable and the associated costs can be reliably estimated. Generally, the timing of recognition of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The amount recognized is the best estimate of the expenditure required. Where the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure.

Employee benefits

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of the group. Deferred bonus arrangements that have a vesting date more than 12 months after the period end are valued on an actuarial basis using the projected unit credit method and amortized on a straight-line basis over the service period until the award vests. The accounting policy for pensions and other post-retirement benefits is described below.

Share-based payments

Equity-settled transactions

The cost of equity-settled transactions with employees is measured by reference to the fair value at the date at which equity instruments are granted and is recognized as an expense over the vesting period, which ends on the date on which the relevant employees become fully entitled to the award. Fair value is determined by using an appropriate valuation model. In valuing equity-settled transactions, no account is taken of any vesting conditions, other than conditions linked to the price of the shares of the company (market conditions). Non-vesting conditions, such as the condition that employees contribute to a savings-related plan, are taken into account in the grant-date fair value, and failure to meet a non-vesting condition is treated as a cancellation, where this is within the control of the employee.

No expense is recognized for awards that do not ultimately vest, except for awards where vesting is conditional upon a market condition, which are treated as vesting irrespective of whether or not the market condition is satisfied, provided that all other performance conditions are satisfied.

At each balance sheet date before vesting, the cumulative expense is calculated, representing the extent to which the vesting period has expired and management s best estimate of the achievement or otherwise of non-market conditions and the number of equity instruments that will ultimately vest or, in the case of an instrument subject to a market condition, be treated as vesting as described above. The movement in cumulative expense since the previous balance sheet date is recognized in the income statement, with a corresponding entry in equity.

When the terms of an equity-settled award are modified or a new award is designated as replacing a cancelled or settled award, the cost based on the original award terms continues to be recognized over the original vesting period. In addition, an expense is recognized over the remainder of the new vesting period for the incremental fair value of any modification, based on the difference between the fair value of the original award and the fair value of the modified award, both as measured on the date of the modification. No reduction is recognized if this difference is negative.

When an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation and any cost not yet recognized in the income statement for the award is expensed immediately.

Notes on financial statements

1. Significant accounting policies continued

Cash-settled transactions

The cost of cash-settled transactions is measured at fair value and recognized as an expense over the vesting period, with a corresponding liability recognized on the balance sheet.

Pensions and other post-retirement benefits

The cost of providing benefits under the defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period (to determine current service cost) and to the current and prior periods (to determine the present value of the defined benefit obligation). Past service costs are recognized immediately when the company becomes committed to a change in pension plan design. When a settlement (eliminating all obligations for benefits already accrued) or a curtailment (reducing future obligations as a result of a material reduction in the scheme membership or a reduction in future entitlement) occurs, the obligation and related plan assets are remeasured using current actuarial assumptions and the resultant gain or loss is recognized in the income statement during the period in which the settlement or curtailment occurs.

The interest element of the defined benefit cost represents the change in present value of scheme obligations resulting from the passage of time, and is determined by applying the discount rate to the opening present value of the benefit obligation, taking into account material changes in the obligation during the year. The expected return on plan assets is based on an assessment made at the beginning of the year of long-term market returns on plan assets, adjusted for the effect on the fair value of plan assets of contributions received and benefits paid during the year. The difference between the expected return on plan assets and the interest cost is recognized in the income statement as other finance income or expense.

Actuarial gains and losses are recognized in full within other comprehensive income in the period in which they occur.

The defined benefit pension plan surplus or deficit in the balance sheet comprises the total for each plan of the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds), less the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price.

Contributions to defined contribution schemes are recognized in the income statement in the period in which they become payable.

Corporate taxes

Income tax expense represents the sum of the tax currently payable and deferred tax. Interest and penalties relating to tax are also included in income tax expense.

The tax currently payable is based on the taxable profits for the period. Taxable profit differs from net profit as reported in the income statement because it excludes items of income or expense that are taxable or deductible in other periods and it further excludes items that are never taxable or deductible. The group s liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is provided, using the liability method, on all temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax liabilities are recognized for all taxable temporary differences:

Except where the deferred tax liability arises on goodwill that is not tax deductible or the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss.

In respect of taxable temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, except where the group is able to control the timing of the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for all deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized:

Except where the deferred income tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss.

In respect of deductible temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred income tax asset to be utilized.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date.

Tax relating to items recognized directly in equity is recognized in equity and not in the income statement.

Customs duties and sales taxes

Revenues, expenses and assets are recognized net of the amount of customs duties or sales tax except:

Where the customs duty or sales tax incurred on a purchase of goods and services is not recoverable from the taxation authority, in which case the customs duty or sales tax is recognized as part of the cost of acquisition of the asset or as part of the expense item as applicable.

Receivables and payables are stated with the amount of customs duty or sales tax included.

The net amount of sales tax recoverable from, or payable to, the taxation authority is included as part of receivables or payables in the balance sheet.

Own equity instruments

The group s holdings in its own equity instruments, including ordinary shares held by Employee Share Ownership Plans (ESOPs), are classified as treasury shares , or own shares for the ESOPs, and are shown as deductions from shareholders equity at cost. Consideration received for the sale of such shares is also recognized in equity, with any difference between the proceeds from sale and the original cost being taken to the profit and loss account reserve. No gain or loss is recognized in the income statement on the purchase, sale, issue or cancellation of equity shares.

Notes on financial statements

1. Significant accounting policies continued

Revenue

Revenue arising from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer and it can be reliably measured.

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods provided in the normal course of business, net of discounts, customs duties and sales taxes.

Revenues associated with the sale of oil, natural gas, natural gas liquids, liquefied natural gas, petroleum and chemicals products and all other items are recognized when the title passes to the customer. Physical exchanges are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange. Similarly, where the group acts as agent on behalf of a third party to procure or market energy commodities, any associated fee income is recognized but no purchase or sale is recorded.

Additionally, where forward sale and purchase contracts for oil, natural gas or power have been determined to be for trading purposes, the associated sales and purchases are reported net within sales and other operating revenues whether or not physical delivery has occurred.

Generally, revenues from the production of oil and natural gas properties in which the group has an interest with joint venture partners are recognized on the basis of the group s working interest in those properties (the entitlement method). Differences between the production sold and the group s share of production are not significant.

Interest income is recognized as the interest accrues (using the effective interest rate that is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset).

Dividend income from investments is recognized when the shareholders right to receive the payment is established.

Research

Research costs are expensed as incurred.

Finance costs

Finance costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use. All other finance costs are recognized in the income statement in the period in which they are incurred.

Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from those estimates.

Impact of new International Financial Reporting Standards

Adopted for 2009

The following new IFRS, and revised or amended IFRSs were adopted by the group with effect from 1 January 2009, IFRS 8 Operating Segments was issued in November 2006 and defines operating segments as components of an entity about which separate financial information is available and is evaluated regularly by the chief operating decision maker in deciding how to allocate resources and in assessing performance. BP s operating segments did not change as a result of adopting the new standard and there was no effect on the group s reported income or net assets. The disclosures required by the standard are included in this report, including the measures as used by the chief operating decision maker.

In September 2007, the IASB issued a revised version of IAS 1 Presentation of Financial Statements , which requires separate presentation of owner and non-owner changes in equity by introducing the statement of comprehensive income. The statement of recognized income and expense is no longer presented. Whenever there is a restatement or reclassification, an additional balance sheet, as at the beginning of the earliest period presented, will be required to be published. There was no effect on the group s reported income or net assets as a result of the adoption of this revised standard.

In March 2009, the IASB issued Amendments to IFRS 7 Financial Instruments: Disclosures Improving Disclosures about Financial Instruments , which requires enhanced disclosures about fair value measurements and liquidity risk. There was no effect on the group s reported income or net assets. The disclosures required by the standard are included in this report.

In addition, several other standards and interpretations were adopted in the year which had no significant impact on the financial statements.

Not yet adopted

The following pronouncements from the IASB will become effective for future financial reporting periods and have not yet been adopted by the group.

In January 2008, the IASB issued a revised version of IFRS 3 Business Combinations . The revised standard still requires the purchase method of accounting to be applied to business combinations but will introduce some changes to the existing accounting treatment. For example, contingent consideration is measured at fair value at the date of acquisition and subsequently remeasured to fair value with changes recognized in profit or loss. Goodwill may be calculated based on the parent s share of net assets or it may include goodwill related to the minority interest. All transaction costs are expensed. The standard is applicable to business combinations occurring in accounting periods beginning on or after 1 July 2009 and BP will adopt it with effect from 1 January 2010. Assets and liabilities arising from business combinations that occurred before the date of adoption by the group will not be restated and thus there will be no effect on the group s reported income or net assets on adoption. The revised standard has been adopted by the EU.

Also in January 2008, the IASB issued an amended version of IAS 27 Consolidated and Separate Financial Statements . This requires the effects of all transactions with non-controlling interests to be recorded in equity if there is no change in control. When control is lost, any remaining interest in the entity is remeasured to fair value and a gain or loss recognized in profit or loss. The amendment is effective for annual periods beginning on or after 1 July 2009 and is to be applied retrospectively, with certain exceptions. BP will adopt the amendment with effect from 1 January 2010 and there will be no effect on the group s reported income or net assets on adoption. The revised standard has been adopted by the EU.

In November 2009, the IASB issued IFRS 9 Financial Instruments which deals with the classification and measurement of financial assets. This new standard represents the first phase of the IASB s project to replace IAS 39 Financial Instruments: Recognition and Measurement . The new standard is effective for annual periods beginning on or after 1 January 2013 with transitional arrangements depending upon the date of initial application. BP has not yet decided the date of initial application for the group and has not yet completed its evaluation of the effect of adoption. The new standard has not yet been adopted by the EU.

There are no other standards and interpretations in issue but not yet adopted that the directors anticipate will have a material effect on the reported income or net assets of the group.

Notes on financial statements

2. Acquisitions

Acquisitions in 2009

BP made no significant acquisitions in 2009.

Acquisitions in 2008

BP made a number of acquisitions in 2008 for a total consideration of $403 million. These business combinations were in the Exploration and Production segment and Other businesses and corporate and the most significant was the acquisition of Whiting Clean Energy, a cogeneration power plant. Fair value adjustments were made to the acquired assets and liabilities.

Acquisitions in 2007

BP made a number of acquisitions in 2007 for a total consideration of $1,200 million. These business combinations were predominantly in the Refining and Marketing segment, the most significant of which was the acquisition of Chevron s Netherlands manufacturing company, Texaco Raffiniderij Pernis B.V. The acquisition included Chevron s 31% minority shareholding in Nerefco, its 31% shareholding in the 22.5MW 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. Fair value adjustments were made to the acquired assets and liabilities. Goodwill of $270 million arose on these acquisitions.

3. Disposals and impairment

			$ million
	2009	2008	2007
Proceeds from disposal of businesses, net of cash disposed of	**966**	11	2,518
Proceeds from disposal of fixed assets	**1,715**	918	1,749
	2,681	929	4,267
By business			
Exploration and Production	**940**	19	1,280
Refining and Marketing	**1,294**	813	2,953
Other businesses and corporate	**447**	97	34
	2,681	929	4,267

Deferred consideration relating to disposals of businesses and fixed assets at 31 December 2009 amounted to $807 million receivable within one year (2008 $15 million and 2007 $22 million) and $691 million receivable after one year (2008 $64 million and 2007 $84 million).

			$ million
	2009	2008	2007
Gains on sale of businesses and fixed assets			
Exploration and Production	**1,717**	34	954
Refining and Marketing	**384**	1,258	1,464
Other businesses and corporate	**72**	61	69

	2,173	1,353	2,487

			$ million
	2009	2008	2007
Losses on sale of businesses and fixed assets			
Exploration and Production	**28**	18	42
Refining and Marketing	**154**	297	313
Other businesses and corporate	**21**	1	
	203	316	355
Impairment losses			
Exploration and Production	**118**	1,186	292
Refining and Marketing	**1,834**	159	1,186
Other businesses and corporate	**189**	227	83
	2,141	1,572	1,561
Impairment reversals			
Exploration and Production	**(3)**	(155)	(237)
Other businesses and corporate	**(8)**		
	(11)	(155)	(237)
Impairment and losses on sale of businesses and fixed assets	**2,333**	1,733	1,679

Notes on financial statements

3. Disposals and impairment continued

Disposals

As part of the strategy to upgrade the quality of its asset portfolio, the group has an active programme to dispose of non-strategic assets. In the normal course of business in any particular year, the group may sell interests in exploration and production properties, service stations and pipeline interests as well as non-core businesses. The group may also dispose of other assets, such as refineries, when this meets strategic objectives.

Exploration and Production

The group divested interests in a number of oil and natural gas properties in all three years. In 2009, the major transactions were the sale of BP West Java Limited in Indonesia, the sale of our 49.9% interest in Kazakhstan Pipeline Ventures LLC and the sale of our 46% stake in LukArco, all of which resulted in gains. We also exchanged interests in a number of fields in the North Sea with BG Group plc.

There were no significant disposals in 2008.

During 2007, the major transactions were the disposal of an exploration and production and gas infrastructure business in the Netherlands and the divestments of our interests in non-core Permian assets in the US and in the Entrada field in the Gulf of Mexico, all of which resulted in gains. We also sold our interests in a number of fields in Egypt, Canada and the US.

Refining and Marketing

In 2009, gains on disposal mainly resulted from the disposal of our ground fuels marketing business in Greece and retail churn in the US, Europe and Australasia. Losses resulted from the continued disposal of company-owned and company-operated retail sites in the US, retail churn and disposals of assets elsewhere in the segment portfolio. Retail churn is the overall process of acquiring and disposing of retail sites by which the group aims to improve the quality and mix of its portfolio of service stations.

In 2008, the major transactions resulting in gains were the contribution of our Toledo refinery to a US jointly controlled entity in an exchange transaction with Husky Energy and the disposals of our interest in the Dixie Pipeline and certain retail assets in the US. The losses on sale related mainly to the disposal of retail assets in the US and Europe. In addition, certain assets at our Acetyls plant in Hull, UK, and other interests in the UK and Europe were sold.

During 2007, we disposed of the Coryton refinery in the UK, our interest in the West Texas Pipeline in the US, and our interest in the Samsung Petrochemical Company in South Korea, all of which resulted in gains. Losses were incurred related to the decision to withdraw from the company-owned and company-operated channel of trade in the US and retail churn.

Other businesses and corporate

During 2009, we disposed of our wind energy business in India and contributed our Fowler II wind energy development asset in exchange for a 50% equity interest in a jointly controlled entity, Fowler II Holdings LLC. In addition, there was a return of capital in the jointly controlled entity Fowler Ridge Wind Farm LLC which did not change our percentage interest in the entity.

Summarized financial information for the sale of businesses is shown below.

			$ million
	2009	2008	2007
Non-current assets	**536**	759	753
Current assets	**444**	485	587
Non-current liabilities	**(146)**		(64)
Current liabilities	**(152)**	(134)	(27)

Total carrying amount of net assets disposed	**682**	1,110	1,249
Recycling of foreign exchange on disposal	**(27)**		(147)
Costs on disposal	**3**	7	22
	658	1,117	1,124
Profit (loss) on sale of businesses[a]	**314**	1,721	1,384
Total consideration	**972**	2,838	2,508
Fair value of interest received in a jointly controlled entity		(2,838)	
Consideration received (receivable)[b]	**(6)**	11	10
Proceeds from the sale of businesses[c]	**966**	11	2,518

[a]Of which $929 million gain was not recognized in the income statement in 2008 as it represented an unrealized gain on the transfer of the Toledo refinery into a jointly controlled entity.
[b]Consideration received from prior year business disposals or not yet received from current year disposals.
[c]Net of cash and cash equivalents disposed of $91 million (2008 nil and 2007 $115 million).

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3. Disposals and impairment continued

Impairment

In assessing whether a write-down is required in the carrying value of a potentially impaired intangible asset, item of property, plant and equipment or an equity-accounted investment, the asset s carrying value is compared with its recoverable amount. The recoverable amount is the higher of the asset s fair value less costs to sell and value in use. Unless indicated otherwise, the recoverable amount used in assessing the impairment charges described below is value in use. The group estimates value in use using a discounted cash flow model. The future cash flows are adjusted for risks specific to the asset and are discounted using a pre-tax discount rate. This discount rate is derived from the group s post-tax weighted average cost of capital and is adjusted where applicable to take into account any specific risks relating to the country where the cash generating unit is located, although other rates may be used if appropriate to the specific circumstances. In 2009 the rates ranged from 9% to 13% (2008 11% to 13%). The rate applied in each country is re-assessed each year. In certain circumstances the fair value less costs to sell may be available for an asset. On occasion, an impairment assessment may be carried out using fair value less costs to sell as the recoverable amount when, for example, a recent market transaction for a similar asset has taken place. For impairments of available-for-sale financial assets that are quoted investments, the fair value is determined by reference to bid prices at the close of business at the balance sheet date. Any cumulative loss previously recognized in other comprehensive income is transferred to the income statement.

Exploration and Production

During 2009, the Exploration and Production segment recognized impairment losses of $118 million. The main elements were the write-down of our $42 million investment in the East Shmidt interest in Russia, triggered by a decision to not proceed to development; a $62 million charge associated with our nErgize gas scheduling system; and several other individually insignificant impairment charges amounting to $14 million.

During 2008, the Exploration and Production segment recognized impairment losses of $1,186 million. The main elements were the write-down of our investment in Rosneft by $517 million, to its fair value determined by reference to an active market, due to a significant decline in the market value of the investment (see Note 25), impairment of oil and gas properties in the Gulf of Mexico of $270 million triggered by downward revisions of reserves, an impairment of exploration assets in Vietnam of $210 million following BP s decision to withdraw from activities in the area concerned, impaiment of oil and gas properties in Egypt of $85 million triggered by cost increases, and several other individually insignificant impairment charges amounting to $104 million.

These charges were partly offset by reversals of previously recognized impairment losses amounting to $155 million. Of this total, $122 million resulted from a reassessment of the economics of Rhourde El Baguel in Algeria.

During 2007, the Exploration and Production segment recognized impairment losses of $292 million. The main elements were a charge of $112 million relating to the cancellation of the DF1 project in Scotland, a $103 million partner loan write-off as a result of unsuccessful drilling in the West Shmidt licence block in Sakhalin and a $52 million write-off of the Whitney Canyon gas plant in US Lower 48 driven by management s decision to abandon this facility. In addition, there were several individually insignificant impairment charges, triggered by downward reserves revisions, amounting to $25 million in total.

These charges were largely offset by reversals of previously recognized impairment charges amounting to $237 million. Of this total, $208 million resulted from a reassessment of the decommissioning liability for damaged platforms in the Gulf of Mexico Shelf. The remaining $29 million related to other individually insignificant impairment reversals, resulting from favourable revisions to the estimates used in determining the assets recoverable amounts.

Refining and Marketing

During 2009, an impairment loss of $1,579 million was recognized against the goodwill allocated to the US West Coast fuels value chain (FVC). The goodwill was originally recognized at the time of the ARCO acquisition in 2000.

The prevailing weak refining environment, together with a review of future margin expectations in the FVC, has led to a reduction in the expected future cash flows. Further information, including details of the group s approach to impairment reviews of goodwill, is given in Note 8. Other impairment losses were also recognized by the segment on a number of assets which amounted to $255 million.

During 2008, the Refining and Marketing segment recognized impairment losses on a number of assets which amounted to $159 million.

The main component of the 2007 impairment charge of $1,186 million arose because of a decision to sell our company-owned and company-operated sites in the US resulting in a $610 million write-down of the carrying amount of the sites to fair value less costs to sell. Following a decision to sell certain assets at our Acetyls plant in Hull, UK, we wrote down the carrying amount of these assets to fair value less costs to sell leading to an impairment charge of $186 million. Changing marketing conditions led to impairments in Samsung Petrochemical Company, to fair value less costs to sell, and in China American Petrochemical Company amounting to $165 million. The balance relates principally to the write-downs of assets elsewhere in the segment portfolio.

Other businesses and corporate

During 2009 and 2008, Other businesses and corporate recognized impairment losses totalling $189 million and $227 million respectively related to various assets in the Alternative Energy business. The impairment loss of $83 million in 2007 related to various individually insignificant write-downs.

4. Segmental analysis

The group s organizational structure reflects the different activities in which BP is engaged. In 2009, BP had two reportable segments: Exploration and Production and Refining and Marketing. BP s activities in low-carbon energy are managed through our Alternative Energy business, which is reported in Other businesses and corporate. The group is managed on an integrated basis.

Exploration and Production s activities cover three key areas. Upstream activities include oil and natural gas exploration, field development and production. Midstream activities include pipeline, transportation and processing activities related to our upstream activities. Marketing and trading activities include the marketing and trading of natural gas, including liquefied natural gas (LNG), together with power and natural gas liquids (NGLs).

Refining and Marketing s activities include the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum and petrochemicals products and related services.

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4. Segmental analysis continued

Other businesses and corporate comprises the Alternative Energy business, Shipping, the group s aluminium asset, Treasury (which in the segmental analysis includes all of the group s cash, cash equivalents and associated interest income), and corporate activities worldwide. The Alternative Energy business is an operating segment that has been aggregated with the other activities within Other businesses and corporate as it does not meet the materiality thresholds for separate segment reporting.

The accounting policies of the operating segments are the same as the group s accounting policies described in Note 1. However, IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker for the purposes of performance assessment and resource allocation. For BP, this measure of profit or loss is replacement cost profit before interest and tax which reflects the replacement cost of supplies by excluding from profit inventory holding gains and losses[a]. Replacement cost profit for the group is not a recognized GAAP measure.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenues and segment results include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers are based on the location of the seller. The UK region includes the UK-based international activities of Refining and Marketing.

All surpluses and deficits recognized on the group balance sheet in respect of pension and other post-retirement benefit plans are allocated to Other businesses and corporate. However, the periodic expense relating to these plans is allocated to the other operating segments based upon the business in which the employees work.

Certain financial information is provided separately for the US as this is an individually material country for BP, and for the UK as this is BP s country of domicile.

					$ million
					2009
By business	**Exploration and Production**	**Refining and Marketing**	**Other businesses and corporate**	**Consolidation adjustment and eliminations**	**Total group**
Segment revenues					
Sales and other operating revenues	**57,626**	**213,050**	**2,843**	**(34,247)**	**239,272**
Less: sales between businesses	**(32,540)**	**(821)**	**(886)**	**34,247**	
Third party sales and other operating revenues	**25,086**	**212,229**	**1,957**		**239,272**
Equity-accounted earnings	**3,309**	**558**	**34**		**3,901**
Interest revenues	**98**	**32**	**95**		**225**
Segment results					
Replacement cost profit (loss) before interest and taxation	**24,800**	**743**	**(2,322)**	**(717)**	**22,504**
Inventory holding gains[a]	**142**	**3,774**	**6**		**3,922**
Profit (loss) before interest and taxation	**24,942**	**4,517**	**(2,316)**	**(717)**	**26,426**

Finance costs					**(1,110)**
Net finance expense relating to pensions and other post-retirement benefits					**(192)**
Profit before taxation					**25,124**
Other income statement items					
Depreciation, depletion and amortization	**9,557**	**2,236**	**313**		**12,106**
Impairment losses	**118**	**1,834**	**189**		**2,141**
Impairment reversals	**3**		**8**		**11**
Fair value (gain) loss on embedded derivatives	**(664)**	**57**			**(607)**
Charges for provisions, net of write-back of unused provisions, including change in discount rate	**307**	**756**	**488**		**1,551**
Segment assets					
Segment assets	**140,149**	**82,224**	**17,954**	**(5,084)**	**235,243**
Current tax receivable					**209**
Deferred tax assets					**516**
Total assets					**235,968**
Includes					
Equity-accounted investments	**20,289**	**6,882**	**1,088**		**28,259**
Additions to non-current assets	**15,855**	**4,083**	**1,297**		**21,235**
Additions to other investments					**19**
Element of acquisitions not related to non-current assets					**(7)**
Additions to decommissioning asset					**(938)**
Capital expenditure and acquisitions	**14,896**	**4,114**	**1,299**		**20,309**

[a]Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies incurred during the period and the cost of sales calculated on the first-in first-out (FIFO) method including any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on the historic cost of acquisition or manufacture rather than the current replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed represent the difference between the charge to the income statement on a FIFO basis (and any related movements in net realizable value provisions) and the charge that would arise using average cost of supplies incurred during the period. For this purpose, average cost of supplies incurred during the period is calculated by dividing the total cost of inventory purchased in the period by the number of barrels acquired. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions.

Notes on financial statements

4. Segmental analysis continued

$ million

By business	Exploration and Production	Refining and Marketing	Other businesses and corporate	Consolidation adjustment and eliminations	2008 Total group
Segment revenues					
Sales and other operating revenues	86,170	320,039	4,634	(49,700)	361,143
Less: sales between businesses	(45,931)	(1,918)	(1,851)	49,700	
Third party sales and other operating revenues	40,239	318,121	2,783		361,143
Equity-accounted earnings	3,565	131	125		3,821
Interest revenues	114	35	220		369
Segment results					
Replacement cost profit (loss) before interest and taxation	38,308	4,176	(1,223)	466	41,727
Inventory holding losses[a]	(393)	(6,060)	(35)		(6,488)
Profit (loss) before interest and taxation	37,915	(1,884)	(1,258)	466	35,239
Finance costs					(1,547)
Net finance income relating to pensions and other post-retirement benefits					591
Profit before taxation					34,283
Other income statement items					
Depreciation, depletion and amortization	8,440	2,208	337		10,985
Impairment losses	1,186	159	227		1,572
Impairment reversals	155				155
Fair value (gain) loss on embedded derivatives	163	(57)	5		111
Charges for provisions, net of write-back of unused provisions	573	479	657		1,709
Segment assets					
Segment assets	136,665	75,329	19,079	(3,212)	227,861
Current tax receivable					377

Total assets				228,238
Includes				
Equity-accounted investments	20,131	6,622	1,073	27,826
Additions to non-current assets	21,584	6,636	1,802	30,022
Additions to other investments				52
Element of acquisitions not related to non-current assets				11
Additions to decommissioning asset				615
Capital expenditure and acquisitions	22,227	6,634	1,839	30,700

[a]Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies incurred during the period and the cost of sales calculated on the first-in first-out (FIFO) method including any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on the historic cost of acquisition or manufacture rather than the current replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed represent the difference between the charge to the income statement on a FIFO basis (and any related movements in net realizable value provisions) and the charge that would arise using average cost of supplies incurred during the period. For this purpose, average cost of supplies incurred during the period is calculated by dividing the total cost of inventory purchased in the period by the number of barrels acquired. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions.

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4. Segmental analysis continued

					$ million
					2007
By business	Exploration and Production	Refining and Marketing	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
Segment revenues					
Sales and other operating revenues	65,740	250,221	3,698	(35,294)	284,365
Less: sales between businesses	(32,083)	(1,914)	(1,297)	35,294	
Third party sales and other operating revenues	33,657	248,307	2,401		284,365
Equity-accounted earnings	3,199	542	91		3,832
Interest revenues	202	30	217		449
Segment results					
Replacement cost profit (loss) before interest and taxation	27,602	2,621	(1,209)	(220)	28,794
Inventory holding gains (losses)[a]	127	3,455	(24)		3,558
Profit (loss) before interest and taxation	27,729	6,076	(1,233)	(220)	32,352
Finance costs					(1,393)
Net finance income relating to pensions and other post-retirement benefits					652
Profit before taxation					31,611
Other income statement items					
Depreciation, depletion and amortization	7,856	2,421	302		10,579
Impairment losses	292	1,186	83		1,561
Impairment reversals	237				237
Fair value loss on embedded derivatives			7		7
Charges for provisions, net of write-back of unused provisions	484	638	280		1,402
Segment assets					
Segment assets	125,736	95,311	20,595	(6,271)	235,371
Current tax receivable					705
Total assets					236,076

Includes				
Equity-accounted investments	16,770	5,268	654	22,692
Additions to non-current assets	15,535	5,437	916	21,888
Additions to other investments				23
Element of acquisitions not related to non-current assets				56
Additions to decommissioning asset				(1,326)
Capital expenditure and acquisitions	14,207	5,495	939	20,641

[a]Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies incurred during the period and the cost of sales calculated on the first-in first-out (FIFO) method including any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on the historic cost of acquisition or manufacture rather than the current replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed represent the difference between the charge to the income statement on a FIFO basis (and any related movements in net realizable value provisions) and the charge that would arise using average cost of supplies incurred during the period. For this purpose, average cost of supplies incurred during the period is calculated by dividing the total cost of inventory purchased in the period by the number of barrels acquired. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions.

Notes on financial statements

4. Segmental analysis continued

By geographical area	**US**	**Non-US**	$ million **2009** **Total**
Revenues			
Third party sales and other operating revenues[a]	**83,982**	**155,290**	**239,272**
Results			
Replacement cost profit before interest and taxation	**2,806**	**19,698**	**22,504**
Non-current assets			
Other non-current assets[b c]	**64,529**	**93,580**	**158,109**
Other investments			**1,567**
Loans			**1,039**
Other receivables			**1,729**
Derivative financial instruments			**3,965**
Deferred tax assets			**516**
Defined benefit pension plan surpluses			**1,390**
Total non-current assets			**168,315**
Capital expenditure and acquisitions	**9,865**	**10,444**	**20,309**

[a]Non-US region includes UK $51,172 million.

[b]Non-US region includes UK $16,713 million.

[c]Excluding financial instruments, deferred tax assets and post-employment benefit plan surpluses.

By geographical area	US	Non-US	$ million 2008 Total
Revenues			
Third party sales and other operating revenues[a]	123,364	237,779	361,143

Results			
Replacement cost profit before interest and taxation	10,678	31,049	41,727
Non-current assets			
Other non-current assets[b c]	62,679	89,823	152,502
Other investments			855
Loans			995
Other receivables			710
Derivative financial instruments			5,054
Defined benefit pension plan surpluses			1,738
Total non-current assets			161,854
Capital expenditure and acquisitions	16,046	14,654	30,700

[a]Non-US region includes UK $81,773 million.

[b]Non-US region includes UK $15,990 million.

[c]Excluding financial instruments, and post-employment benefit plan surpluses.

			$ million
			2007
By geographical area	US	Non-US	Total
Revenues			
Third party sales and other operating revenues[a]	102,319	182,046	284,365
Results			
Replacement cost profit before interest and taxation	5,581	23,213	28,794
Non-current assets			
Other non-current assets[b c]	51,840	87,582	139,422
Other investments			1,830
Loans			999
Other receivables			968
Derivative financial instruments			3,741
Defined benefit pension plan surplus			8,914
Total non-current assets			155,874

Capital expenditure and acquisitions	7,487	13,154	20,641

[a]Non-US region includes UK $61,149 million.

[b]Non-US region includes UK $19,302 million.

[c]Excluding financial instruments and post-employment benefit plan surpluses.

Notes on financial statements

5. Interest and other income

			$ million
	2009	2008	2007
Interest income			
Interest income from available-for-sale financial assets[a]	**15**	32	5
Interest income from loans and receivables[a]	**69**	163	175
Interest from loans to equity-accounted entities	**53**	115	172
Other interest	**88**	59	97
	225	369	449
Other income			
Dividend income from available-for-sale financial assets[a]	**32**	37	29
Other income	**535**	330	276
	567	367	305
	792	736	754

[a]Total interest and other income related to financial instruments amounted to $116 million (2008 $232 million and 2007 $209 million).

6. Production and similar taxes

			$ million
	2009	2008	2007
US	**649**	2,602	1,260
Non-US	**3,103**	6,351	4,443
	3,752	8,953	5,703

Comparative figures have been restated to include amounts previously reported as production and manufacturing expenses amounting to $2,427 million for 2008 and $1,690 million for 2007 which we believe are more appropriately classified as production taxes. There was no effect on the group profit or the group balance sheet.

7. Depreciation, depletion and amortization

			$ million
By business	**2009**	2008	2007
Exploration and Production			

US	**4,150**	3,012	2,365
Non-US	**5,407**	5,428	5,491
	9,557	8,440	7,856
Refining and Marketing			
US	**919**	825	1,076
Non-US[a]	**1,317**	1,383	1,345
	2,236	2,208	2,421
Other businesses and corporate			
US	**136**	132	117
Non-US	**177**	205	185
	313	337	302
By geographical area			
US	**5,205**	3,969	3,558
Non-US[a]	**6,901**	7,016	7,021
	12,106	10,985	10,579

[a]Non-US area includes the UK-based international activities of Refining and Marketing.

Notes on financial statements

8. Impairment review of goodwill

Goodwill at 31 December	**2009**	$ million 2008
Exploration and Production	**4,297**	4,297
Refining and Marketing	**4,245**	5,462
Other businesses and corporate	**78**	119
	8,620	9,878

Goodwill acquired through business combinations has been allocated to groups of cash-generating units that are expected to benefit from the synergies of the acquisition. For Exploration and Production, goodwill has been allocated to each geographic region, that is UK, Rest of Europe, US and Rest of World, and for Refining and Marketing, goodwill has been allocated to the Rhine fuels value chain (FVC), US West Coast FVC, Lubricants and Other.

In assessing whether goodwill has been impaired, the carrying amount of the cash-generating unit (including goodwill) is compared with the recoverable amount of the cash-generating unit. The recoverable amount is the higher of fair value less costs to sell and value in use. In the absence of any information about the fair value of a cash-generating unit, the recoverable amount is deemed to be the value in use.

The group calculates the recoverable amount as the value in use using a discounted cash flow model. The future cash flows are adjusted for risks specific to the cash-generating unit and are discounted using a pre-tax discount rate. The discount rate is derived from the group s post-tax weighted average cost of capital and is adjusted where applicable to take into account any specific risks relating to the country where the cash-generating unit is located. The rate to be applied to each country is reassessed each year. A discount rate of 11% has been used for all goodwill impairment calculations performed in 2009 (2008 11%).

The business segment plans, which are approved on an annual basis by senior management, are the primary source of information for the determination of value in use. They contain forecasts for oil and natural gas production, refinery throughputs, sales volumes for various types of refined products (e.g. gasoline and lubricants), revenues, costs and capital expenditure. As an initial step in the preparation of these plans, various environmental assumptions, such as oil prices, natural gas prices, refining margins, refined product margins and cost inflation rates, are set by senior management. These environmental assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability.

Exploration and Production

				2009				$ million 2008
	UK	**US**	**Rest of World**	**Total**	UK	US	Rest of World	Total
Goodwill	**341**	**3,441**	**515**	**4,297**	341	3,441	515	4,297
Excess of recoverable amount over carrying amount	**7,721**	**15,528**	**n/a**	**n/a**	7,972	16,692	n/a	n/a

The value in use is based on the cash flows expected to be generated by the projected oil or natural gas production profiles up to the expected dates of cessation of production of each producing field. As the production profile and related cash flows can be estimated from the company s past experience, management believes that the cash flows generated over the estimated life of field is the appropriate basis upon which to assess goodwill and individual assets for impairment. The date of cessation of production depends on the interaction of a number of variables, such as the recoverable quantities of hydrocarbons, the production profile of the hydrocarbons, the cost of the development of the infrastructure necessary to recover the hydrocarbons, the production costs, the contractual duration of the production concession and the selling price of the hydrocarbons produced. As each producing field has specific reservoir characteristics and economic circumstances, the cash flows of the fields are computed using appropriate individual economic models and key assumptions agreed by BP s management for the purpose. Capital expenditure and operating costs for the first four years and expected hydrocarbon production profiles up to 2020 are derived from the business segment plan. Estimated production quantities and cash flows up to the date of cessation of production on a field-by-field basis are developed to be consistent with this. The production profiles used are consistent with the resource volumes approved as part of BP s centrally-controlled process for the estimation of proved reserves and total resources.

Consistent with prior years, the 2009 review for impairment was carried out during the fourth quarter. As permitted by IAS 36, the detailed calculations of recoverable amount performed in 2008 for the US and the UK, and calculations performed in 2005 for the Rest of World, were used for the 2009 impairment test as the criteria of IAS 36 were considered to be satisfied: the excess of the recoverable amount over the carrying amount (the headroom) was substantial in 2008 (for the US and the UK) and 2005 (for the Rest of World); there had been no significant change in the assets and liabilities; and the likelihood that the recoverable amount would be less than the carrying amount at the time of the test was remote.

The table above shows the carrying amount of the goodwill allocated to each of the regions of the Exploration and Production segment and, where required, the headroom in the cash-generating units to which the goodwill has been allocated. The estimates of headroom at 31 December 2009 for the UK and the US are based on recoverable amounts determined in 2008 and carrying amounts at 31 December 2009. No impairment charge is required.

For 2008, the Brent oil price assumption was an average $49 per barrel in 2009, $59 per barrel in 2010, $65 per barrel in 2011, $68 per barrel in 2012, $70 per barrel in 2013 and $75 per barrel in 2014 and beyond. The Henry Hub natural gas price assumption was an average of $6.16/mmBtu in 2009, $7.15/mmBtu in 2010, $7.34/mmBtu in 2011, $7.62/mmBtu in 2012, $7.60/mmBtu in 2013 and $7.50/mmBtu in 2014 and beyond. The prices for the first five years were derived from forward price curves at the year-end. Prices in 2014 and beyond were determined using long-term views of global supply and demand, building upon past experience of the industry and consistent with a number of external economic forecasts. These prices were adjusted to arrive at appropriate consistent price assumptions for different qualities of oil and gas.

The key assumptions required for the value-in-use estimation are the oil and natural gas prices, production volumes and the discount rate. To test the sensitivity of the headroom to changes in production volumes and oil and natural gas prices, management has developed rules of thumb for key assumptions. Applying these gives an indication of the impact on the headroom of possible changes in the key assumptions.

Notes on financial statements

8. Impairment review of goodwill continued
In the prior year it was estimated that the long-term price of oil that would cause the recoverable amount to be equal to the carrying amount for each cash-generating unit would be of the order of $38 per barrel for the UK and $50 per barrel for the US. It was estimated that the long-term price of gas that would cause the total recoverable amount to be equal to the total carrying amount of goodwill and related non-current assets for the US cash-generating unit would be of the order of $4/mmBtu (Henry Hub). As a significant amount of gas from the North Sea is sold under fixed-price contracts, or contracts priced using non-gas indices, it was estimated that no reasonably possible change in gas prices would cause the UK headroom to be reduced to zero. It was estimated that no reasonably possible change in oil and gas prices would cause the headroom in Rest of World to be reduced to zero.

Estimated production volumes are based on detailed data for the fields and take into account development plans for the fields agreed by management as part of the long-term planning process. In 2008, it was estimated that, if all our production were to be reduced by 10% for the whole of the next 15 years, this would not be sufficient to reduce the excess of recoverable amount over the carrying amounts of each cash-generating unit to zero. Consequently, management believes no reasonably possible change in the production assumption would cause the carrying amounts to exceed the recoverable amounts.

Management also believes that currently there is no reasonably possible change in discount rate that would cause the carrying amounts in the UK, US or Rest of World to exceed the recoverable amounts.

Refining and Marketing

									$ million
				2009					2008
	Rhine FVC	**Lubricants**	**Other**	**Total**	Rhine FVC	US West Coast FVC	Lubricants	Other	Total
Goodwill	**655**	**3,416**	**174**	**4,245**	637	1,579	3,043	203	5,462
Excess of recoverable amount over carrying amount	**2,034**	**n/a**	**n/a**	**n/a**	3,603	1,629	5,445	n/a	n/a

For all cash-generating units, the cash flows for the first two or five years are derived from the business segment plan. For determining the value in use for each of the cash-generating units, cash flows for a period of 10 years have been discounted and aggregated with a terminal value.

Rhine FVC

As a result of the continuing integration of our businesses into fuels value chains, convenience retail operations in the Rhine region were incorporated into the Rhine FVC from the beginning of 2009. The key assumptions to which the calculation of value in use for the Rhine FVC is most sensitive are refinery gross margins, production volumes, and discount rate. Refinery gross margins used in the plan are derived from assumptions that are consistent with those used to develop the regional Global Indicator Margin (GIM). The regional GIM is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity available in the region. The average values assigned to the regional GIM and refinery production volume over the plan period are $4.05 per barrel and 254mmbbl a year (2008 $5.50 per barrel and 250mmbbl a year). The values reflect past experience and are consistent with external sources. Cash flows beyond the five-year plan period are extrapolated using a 2.4% growth rate (2008 cash flows beyond the three-year plan period were extrapolated using a 1.2% growth rate).

2009

Sensitivity analysis

Sensitivity of value in use to a change in refinery margins of $1 per barrel ($ billion)	**2.2**
Adverse change in refinery margins to reduce recoverable amount to carrying amount ($ per barrel)	**0.9**
Sensitivity of value in use to a 5% change in production volume ($ billion)	**0.8**
Adverse change in production volume to reduce recoverable amount to carrying amount (mmbbl per year)	**31**
Sensitivity of value in use to a change in the discount rate of 1% ($ billion)	**0.8**
Discount rate to reduce recoverable amount to carrying amount	**14%**

Lubricants

The key assumptions to which the calculation of value in use for the Lubricants unit is most sensitive are operating unit margins, sales volumes, and discount rate. The values assigned to these key assumptions reflect past experience. No reasonably possible change in any of these key assumptions would cause the unit s carrying amount to exceed its recoverable amount. For 2008 the average values assigned to the operating margin and sales volumes over the plan period were 70 cents per litre and 3.4 billion litres per year, respectively. Cash flows beyond the two-year plan period are extrapolated using a 3% growth rate (2008 cash flows beyond the three-year plan period were extrapolated using a 3% growth rate).

US West Coast FVC

As disclosed in Note 3, the impairment review of goodwill allocated to the US West Coast FVC resulted in the recognition of an impairment loss in 2009 to write off the entire balance of $1,579 million. The key assumptions to which the calculation of value in use for the US West Coast FVC was most sensitive in 2008 were refinery gross margins, production volumes and discount rates. The average value assigned to the refinery gross margin during the plan period was based on a $7.60 per barrel regional GIM. The average value assigned to the production volume was 170mmbbl a year over the plan period. Cash flows beyond the three-year plan period were extrapolated using a 2% growth rate. These assumptions reflected past experience and were consistent with external sources.

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9. Distribution and administration expenses

			$ million
	2009	2008	2007
Distribution	**12,798**	14,075	14,028
Administration	**1,240**	1,337	1,343
	14,038	15,412	15,371

10. Currency exchange gains and losses

			$ million
	2009	2008	2007
Currency exchange (gains) losses (credited) charged to income[a]	**193**	156	(201)

[a]Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.

11. Research and development

			$ million
	2009	2008	2007
Expenditure on research and development	**587**	595	566

12. Operating leases

The presentation of operating lease expense and future minimum lease payments has been revised in 2009 in order to provide more meaningful information about the costs incurred by BP under these arrangements, and the associated future commitments. The comparative information has been amended to conform to the revised presentation.

In the case of an operating lease entered into by BP as the operator of a jointly controlled asset, the amounts shown in the tables below represent the net operating lease expense and net future minimum lease payments. These net amounts are after deducting amounts reimbursed, or to be reimbursed, by joint venture partners, whether the joint venture partners have co-signed the lease or not. Where BP is not the operator of a jointly controlled asset, BP s share of the lease expense and future minimum lease payments is included in the amounts shown, whether BP has co-signed the lease or not.

The table below shows the expense for the year in respect of operating leases.

			$ million
	2009	2008	2007
Minimum lease payments	**4,109**	4,114	3,522
Contingent rentals	**(9)**	97	80
Sub-lease rentals	**(133)**	(194)	(183)
	3,967	4,017	3,419

The future minimum lease payments at 31 December, before deducting related rental income from operating sub-leases of $379 million
(2008 $547 million), are shown in the table below. This does not include future contingent rentals. Where the lease rentals are dependent on a variable factor, the future minimum lease payments are based on the factor as at inception of the lease.

		$ million
Future minimum lease payments	**2009**	2008
Payable within		
1 year	**3,251**	3,659
2 to 5 years	**7,334**	7,628
Thereafter	**4,131**	4,864
	14,716	16,151

Notes on financial statements

12. Operating leases continued
The group enters into operating leases of ships, plant and machinery, commercial vehicles and land and buildings. Typical durations of the leases are as follows:

	Years
Ships	up to 15
Plant and machinery	up to 10
Commercial vehicles	up to 15
Land and buildings	up to 40

The group has entered into a number of structured operating leases for ships and in most cases the lease rental payments vary with market interest rates. The variable portion of the lease payments above or below the amount based on the market interest rate prevailing at inception of the lease is treated as contingent rental expense. The group also routinely enters into bareboat charters, time-charters and spot-charters for ships on standard industry terms.

The most significant items of plant and machinery hired under operating leases are drilling rigs used in the Exploration and Production segment. At 31 December 2009 the future minimum lease payments relating to drilling rigs amounted to $4,919 million (2008 $5,531 million). In some cases, drilling rig lease rental rates are adjusted periodically to market rates that are influenced by oil prices and may be significantly different from the rates at the inception of the lease. Differences between the rate paid and rate at inception of the lease are treated as contingent rental expense.

Commercial vehicles hired under operating leases are primarily railcars. Retail service station sites and office accommodation are the main items in the land and buildings category.

The terms and conditions of these operating leases do not impose any significant financial restrictions on the group. Some of the leases of ships and buildings allow for renewals at BP s option.

13. Exploration for and evaluation of oil and natural gas resources
The following financial information represents the amounts included within the group totals relating to activity associated with the exploration for and evaluation of oil and natural gas resources. All such activity is recorded within the Exploration and Production segment.

			$ million
	2009	2008	2007
Exploration and evaluation costs			
Exploration expenditure written off	**593**	385	347
Other exploration costs	**523**	497	409
Exploration expense for the year[a]	**1,116**	882	756
Intangible assets exploration expenditure	**10,388**	9,031	5,252
Net assets	**10,388**	9,031	5,252
Capital expenditure	**2,715**	4,780	2,000
Net cash used in operating activities	**523**	497	409

Net cash used in investing activities	**3,306**	4,163	2,000

[a]In addition to these amounts, an impairment charge of $210 million was recognized in 2008 relating to exploration assets in Vietnam following BP s decision to withdraw from activities in the area concerned.

Notes on financial statements

14. Auditor s remuneration

Fees Ernst & Young	**2009**	2008	$ million 2007
Fees payable to the company s auditors for the audit of the company s accounts[a]	**13**	16	18
Fees payable to the company s auditors and its associates for other services			
Audit of the company s subsidiaries pursuant to legislation	**22**	28	31
Other services pursuant to legislation	**11**	13	14
	46	57	63
Tax services	**1**	2	2
Services relating to corporate finance transactions		2	1
All other services	**6**	5	8
Audit fees in respect of the BP pension plans	**1**	1	1
	54	67	75

[a]Fees in respect of the audit of the accounts of BP p.l.c. including the group s consolidated financial statements. 2008 includes $3 million of additional fees for 2007 and 2007 includes $7 million of additional fees for 2006.

Auditors remuneration is included in the income statement within distribution and administration expenses.

The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young compared with that of other potential service providers. These services are for a fixed term.

Under SEC regulations, the remuneration of the auditor of $54 million (2008 $67 million and 2007 $75 million) is required to be presented as follows: audit services $46 million (2008 $57 million and 2007 $63 million); other audit related services $2 million (2008 $1 million and 2007 $3 million); tax services $1 million (2008 $2 million and 2007 $2 million); and fees for all other services $5 million (2008 $7 million and 2007 $7 million).

15. Finance costs

	2009	2008	$ million 2007
Interest payable	**906**	1,319	1,433
Capitalized at 2.75% (2008 4.00% and 2007 5.70%)[a]	**(188)**	(162)	(323)
Unwinding of discount on provisions	**247**	287	283
Unwinding of discount on other payables	**145**	103	

	1,110	1,547	1,393

[a]Tax relief on capitalized interest is $63 million (2008 $42 million and 2007 $81 million).

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16. Taxation

Tax on profit

			$ million
	2009	2008	2007
Current tax			
Charge for the year	**6,045**	13,468	10,006
Adjustment in respect of prior years	**(300)**	(85)	(171)
	5,745	13,383	9,835
Deferred tax			
Origination and reversal of temporary differences in the current year	**2,131**	(324)	671
Adjustment in respect of prior years	**489**	(442)	(64)
	2,620	(766)	607
Tax on profit	**8,365**	12,617	10,442

Tax included in other comprehensive income

			$ million
	2009	2008	2007
Current tax		(264)	(178)
Deferred tax	**(525)**	(2,682)	454
	(525)	(2,946)	276

Tax included directly in equity

			$ million
	2009	2008	2007
Deferred tax	**(65)**	190	(213)

Reconciliation of the effective tax rate

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective tax rate of the group on profit before taxation.

			$ million
	2009	2008	2007

Profit before taxation	**25,124**	34,283	31,611
Tax on profit	**8,365**	12,617	10,442
Effective tax rate	**33%**	37%	33%

		% of profit before taxation	
UK statutory corporation tax rate	**28**	28	30
Increase (decrease) resulting from			
UK supplementary and overseas taxes at higher rates	**8**	14	8
Tax reported in equity-accounted entities	**(3)**	(2)	(2)
Adjustments in respect of prior years	**1**	(2)	(1)
Current year losses unrelieved (prior year losses utilized)		(1)	(1)
Goodwill impairment	**2**		
Tax incentives for investment	**(2)**	(1)	
Other	**(1)**	1	(1)
Effective tax rate	**33**	37	33

Notes on financial statements

16. Taxation continued

Deferred tax

					$ million
		Income statement			Balance sheet
	2009	2008	2007	**2009**	2008
Deferred tax liability					
Depreciation	**1,983**	1,248	125	**25,398**	23,342
Pension plan surpluses	**(6)**	108	127	**271**	412
Other taxable temporary differences	**978**	(2,471)	1,371	**4,307**	3,626
	2,955	(1,115)	1,623	**29,976**	27,380
Deferred tax asset					
Petroleum revenue tax	**44**	121	139	**(142)**	(192)
Pension plan and other post-retirement benefit plan deficits	**180**	104	(72)	**(2,269)**	(2,414)
Decommissioning, environmental and other provisions	**86**	(333)	(1,069)	**(4,930)**	(4,860)
Derivative financial instruments	**80**	228	450	**(243)**	(331)
Tax credits	**(516)**	330	(384)	**(1,034)**	(519)
Loss carry forward	**402**	(212)	(82)	**(1,014)**	(1,302)
Other deductible temporary differences	**(611)**	111	2	**(2,198)**	(1,564)
	(335)	349	(1,016)	**(11,830)**	(11,182)
Net deferred tax (credit) charge and net deferred tax liability	**2,620**	(766)	607	**18,146**	16,198
Of which deferred tax liabilities				**18,662**	16,198
deferred tax assets				**516**	

		$ million
Analysis of movements during the year	**2009**	2008
At 1 January	**16,198**	19,215
Exchange adjustments	**(7)**	(67)
Charge (credit) for the year on profit	**2,620**	(766)
Charge (credit) for the year in other comprehensive income	**(525)**	(2,682)
Charge (credit) for the year in equity	**(65)**	190
Deletions	**(75)**	
Other movements		308
At 31 December	**18,146**	16,198

In 2009 and 2008, there have been no changes in the statutory tax rates that have materially impacted the group s tax charge. In 2007 the enactment of a 2% reduction in the rate of UK corporation tax on profits arising from activities outside the North Sea reduced the deferred tax charge by $189 million in that year.

Deferred tax assets are recognized to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized.

At 31 December 2009, the group had approximately $4.2 billion (2008 $6.3 billion) of carry-forward tax losses, predominantly in Europe, that would be available to offset against future taxable profit. A deferred tax asset has been recognized in respect of $3.2 billion of losses (2008 $4.2 billion). No deferred tax asset has been recognized in respect of $1.0 billion of losses (2008 $2.1 billion). In 2009 the group has been able to utilize $1.1 billion of the losses, previously unrecognized, through other comprehensive income. Of the $1.0 billion losses with no deferred tax asset, $0.2 billion expire in three years and $0.8 billion have no fixed expiry date.

At 31 December 2009, the group had approximately $3.0 billion of unused tax credits predominantly in the US (2008 $3.4 billion in the UK and US). Due to legislative changes in the UK that repealed double taxation relief in relation to foreign dividends, onshore pooling and utilization of eligible unrelieved foreign tax, there are now no UK tax credits carried forward at 31 December 2009. A deferred tax asset of $1.0 billion has been recognized in 2009 in respect of unused tax credits (2008 $0.5 billion). No deferred tax asset has been recognized in respect of $2.0 billion of tax credits (2008 $2.9 billion). The US tax credits with no deferred tax asset, amounting to $2.0 billion (2008 $1.8 billion) expire 10 years after generation, and substantially all expire in the period 2014-2019.

The major components of temporary differences at the end of 2009 are tax depreciation, US inventory holding gains (classified as other taxable temporary differences), provisions and pension plan and other post-retirement benefit plan deficits.

In 2009 there are no material temporary differences associated with investments in subsidiaries and equity-accounted entities for which deferred tax liabilities have not been recognized.

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17. Dividends

	pence per share			cents per share			$ million		
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Dividends announced and paid									
Preference shares							**2**	2	2
Ordinary shares									
March	**9.818**	6.813	5.258	**14.000**	13.525	10.325	**2,619**	2,553	2,000
June	**9.584**	6.830	5.151	**14.000**	13.525	10.325	**2,619**	2,545	1,983
September	**8.503**	7.039	5.278	**14.000**	14.000	10.825	**2,620**	2,623	2,065
December	**8.512**	8.705	5.308	**14.000**	14.000	10.825	**2,623**	2,619	2,056
	36.417	29.387	20.995	**56.000**	55.050	42.300	**10,483**	10,342	8,106
Dividend announced per ordinary share, payable in March 2010	**8.679**			**14.000**			**2,626**		

The group does not account for dividends until they are paid. The accounts for the year ended 31 December 2009 do not reflect the dividend announced on 2 February 2010 and payable in March 2010; this will be treated as an appropriation of profit in the year ended 31 December 2010.

18. Earnings per ordinary share

			cents per share
	2009	2008	2007
Basic earnings per share	**88.49**	112.59	108.76
Diluted earnings per share	**87.54**	111.56	107.84

Basic earnings per ordinary share amounts are calculated by dividing the profit for the year attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. The average number of shares outstanding excludes treasury shares and the shares held by the Employee Share Ownership Plans (ESOPs) and includes certain shares that will be issuable in the future under employee share plans.

For the diluted earnings per share calculation, the weighted average number of shares outstanding during the year is adjusted for the number of shares that are potentially issuable in connection with employee share-based payment plans using the treasury stock method.

			$ million
	2009	2008	2007
Profit attributable to BP shareholders	**16,578**	21,157	20,845
Less dividend requirements on preference shares	**2**	2	2
Diluted profit for the year attributable to BP ordinary shareholders	**16,576**	21,155	20,843

			shares thousand
	2009	2008	2007
Basic weighted average number of ordinary shares	**18,732,459**	18,789,827	19,163,389
Potential dilutive effect of ordinary shares issuable under employee share schemes	**203,232**	172,690	163,486
	18,935,691	18,962,517	19,326,875

The number of ordinary shares outstanding at 31 December 2009, excluding treasury shares and the shares held by the ESOPs, and including certain shares that will be issuable in the future under employee share plans was 18,755,378,211. Between 31 December 2009 and 18 February 2010, the latest practicable date before the completion of these financial statements, there has been a net increase of 12,018,689 in the number of ordinary shares outstanding as a result of share issues in relation to employee share schemes. The number of potential ordinary shares issuable through the exercise of employee share schemes was 215,123,696 at 31 December 2009. There has been an increase of 264,627 in the number of potential ordinary shares between 31 December 2009 and 18 February 2010.

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19. Property, plant and equipment

$ million

	Land and land improvements	Buildings	Oil and gas properties	Plant, machinery and equipment	Fixtures, fittings and office equipment	Transportation	Oil depots, storage tanks and service stations	Total
Cost								
At 1 January 2009	**3,964**	**2,742**	**146,813**	**37,905**	**3,045**	**12,295**	**10,345**	**217,109**
Exchange adjustments	**148**	**85**	**2**	**877**	**83**	**66**	**546**	**1,807**
Additions	**59**	**313**	**11,928**	**3,743**	**145**	**115**	**739**	**17,042**
Transfers			**745**					**745**
Deletions	**(385)**	**(222)**	**(2,291)**	**(926)**	**(251)**	**(35)**	**(1,335)**	**(5,445)**
At 31 December 2009	**3,786**	**2,918**	**157,197**	**41,599**	**3,022**	**12,441**	**10,295**	**231,258**
Depreciation								
At 1 January 2009	**598**	**1,313**	**79,955**	**17,298**	**1,696**	**7,542**	**5,507**	**113,909**
Exchange adjustments	**19**	**38**		**446**	**54**	**30**	**272**	**859**
Charge for the year	**31**	**102**	**8,951**	**1,372**	**302**	**289**	**618**	**11,665**
Impairment losses	**88**	**53**	**10**	**185**	**10**	**8**	**52**	**406**
Deletions	**(165)**	**(117)**	**(1,941)**	**(398)**	**(169)**	**(17)**	**(1,049)**	**(3,856)**
At 31 December 2009	**571**	**1,389**	**86,975**	**18,903**	**1,893**	**7,852**	**5,400**	**122,983**
Net book amount at 31 December 2009	**3,215**	**1,529**	**70,222**	**22,696**	**1,129**	**4,589**	**4,895**	**108,275**
Cost								
At 1 January 2008	4,516	3,150	134,615	36,365	3,169	11,866	11,410	205,091
Exchange adjustments	(320)	(287)	(1)	(1,655)	(237)	(98)	(1,047)	(3,645)
Acquisitions			136	212				348
Additions	64	161	12,571	4,118	530	243	842	18,529
Transfers[a]			(454)	79	(1)	454		78
Deletions	(296)	(282)	(54)	(1,214)	(416)	(170)	(860)	(3,292)
At 31 December 2008	3,964	2,742	146,813	37,905	3,045	12,295	10,345	217,109
Depreciation								
At 1 January 2008	718	1,533	72,486	17,417	1,820	7,126	6,002	107,102
Exchange adjustments	(30)	(118)		(917)	(147)	(41)	(502)	(1,755)
Charge for the year	32	79	7,490	1,697	313	296	709	10,616
Impairment losses	21	33	469	131	1		19	674

Impairment reversals			(122)					(122)
Transfers[b]			(352)	4	(1)	274		(75)
Deletions	(143)	(214)	(16)	(1,034)	(290)	(113)	(721)	(2,531)
At 31 December 2008	598	1,313	79,955	17,298	1,696	7,542	5,507	113,909
Net book amount at 31 December 2008	3,366	1,429	66,858	20,607	1,349	4,753	4,838	103,200
Net book amount at 1 January 2008	3,798	1,617	62,129	18,948	1,349	4,740	5,408	97,989
Assets held under finance leases at net book amount included above								
At 31 December 2009		**14**	**225**	**110**		**7**	**19**	**375**
At 31 December 2008		12	237	107		8	18	382
Decommissioning asset at net book amount included above						Cost	Depreciation	Net
At 31 December 2009						**7,968**	**4,129**	**3,839**
At 31 December 2008						7,140	3,659	3,481
Assets under construction included above								
At 31 December 2009								**19,120**
At 31 December 2008								17,213

[a]Includes $337 million transferred to equity-accounted investments and $415 million transferred from intangible assets.

[b]Includes $75 million transferred to equity-accounted investments.

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20. Goodwill

		$ million
	2009	2008
Cost		
At 1 January	**9,878**	11,006
Exchange adjustments	**350**	(1,112)
Acquisitions		1
Additions		39
Deletions	**(29)**	(56)
At 31 December	**10,199**	9,878
Impairment losses		
At 1 January		
Impairment losses for the year	**(1,579)**	
At 31 December	**(1,579)**	
Net book amount at 31 December	**8,620**	9,878

21. Intangible assets

						$ million
			2009			2008
	Exploration and appraisal expenditure	**Other intangibles**	**Total**	Exploration and appraisal expenditure	Other intangibles	Total
Cost						
At 1 January	**9,425**	**2,927**	**12,352**	5,637	2,898	8,535
Exchange adjustments	**8**	**75**	**83**	(1)	(175)	(176)
Acquisitions				42		42
Additions[a]	**2,715**	**441**	**3,156**	4,738	354	5,092
Transfers	**(745)**		**(745)**	(415)		(415)
Deletions	**(690)**	**(159)**	**(849)**	(576)	(150)	(726)
At 31 December	**10,713**	**3,284**	**13,997**	9,425	2,927	12,352
Amortization						
At 1 January	**394**	**1,698**	**2,092**	385	1,498	1,883
Exchange adjustments		**32**	**32**		(60)	(60)
Charge for the year	**593**	**441**	**1,034**	385	369	754
Impairment losses		**90**	**90**	200		200

Deletions	**(662)**	**(137)**	**(799)**	(576)	(109)	(685)
At 31 December	**325**	**2,124**	**2,449**	394	1,698	2,092
Net book amount at 31 December	**10,388**	**1,160**	**11,548**	9,031	1,229	10,260
Net book amount at 1 January	**9,031**	**1,229**	**10,260**	5,252	1,400	6,652

[a] Included in additions to exploration and appraisal expenditure in 2008 is $2,331 million in relation to BP s purchase of interests in shale gas assets in the US.

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22. Investments in jointly controlled entities

The significant jointly controlled entities of the BP group at 31 December 2009 are shown in Note 43. Summarized financial information for the group s share of jointly controlled entities is shown below.

							$ million
	2009			2008			2007
		TNK-BP	Other	Total	TNK-BP	Other	Total
Sales and other operating revenues	**9,396**	25,936	10,796	36,732	19,463	7,245	26,708
Profit before interest and taxation	**1,815**	3,588	1,343	4,931	3,743	1,299	5,042
Finance costs	**155**	275	185	460	264	176	440
Profit before taxation	**1,660**	3,313	1,158	4,471	3,479	1,123	4,602
Taxation	**374**	882	397	1,279	993	259	1,252
Minority interest		169		169	215		215
Profit for the year	**1,286**	2,262	761	3,023	2,271	864	3,135
Non-current assets	**15,857**	13,874	15,584	29,458			
Current assets	**4,124**	3,760	3,687	7,447			
Total assets	**19,981**	17,634	19,271	36,905			
Current liabilities	**2,276**	3,287	1,998	5,285			
Non-current liabilities	**3,768**	4,820	3,973	8,793			
Total liabilities	**6,044**	8,107	5,971	14,078			
Minority interest		588		588			
	13,937	8,939	13,300	22,239			
Group investment in jointly controlled entities							
Group share of net assets (as above)	**13,937**	8,939	13,300	22,239			
Loans made by group companies to jointly controlled entities	**1,359**		1,587	1,587			
	15,296	8,939	14,887	23,826			

Our investment in TNK-BP was reclassified from a jointly controlled entity to an associate with effect from 9 January 2009, the date that BP finalized a revised shareholder agreement with its Russian partners in TNK-BP, Alfa Access-Renova (AAR). The formerly evenly-balanced main board structure has been replaced by one with four representatives each from BP and AAR, plus three independent directors. The change in accounting classification from a jointly controlled entity to an associate reflected the ability of the independent directors of TNK-BP to decide on certain matters in the event of disagreement between the shareholder representatives on the board. The group s investment continues to be accounted for using the equity method.

In December 2007, BP signed a memorandum of understanding with Husky Energy Inc. (Husky) to form an integrated North American oil sands business. The transaction was completed on 31 March 2008, with BP contributing its Toledo refinery to a US jointly controlled entity to which Husky contributed $250 million cash and a payable of $2,588 million. In Canada, Husky contributed its Sunrise field to a second jointly controlled entity, with BP contributing $250 million in cash and a payable of $2,264 million. Both jointly controlled entities are owned 50:50 by BP and Husky and are accounted for using the equity method.

Transactions between the group and its jointly controlled entities are summarized below.

						$ million
Sales to jointly controlled entities		**2009**		2008		2007
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas, employee services	**2,182**	**1,328**	2,971	1,036	2,336	888

						$ million
Purchases from jointly controlled entities		**2009**		2008		2007
Product	**Purchases**	**Amount payable at 31 December**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**5,377**	**214**	9,115	182	2,067	66

[a]Amounts payable to jointly controlled entities shown above exclude payables relating to BP s contribution on the establishment of the Sunrise Oil Sands joint venture.

The terms of the outstanding balances receivable from jointly controlled entities are typically 30 to 45 days, except for a receivable from Ruhr Oel of $419 million, which will be paid over several years as it relates partly to pension payments. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts. Dividends receivable are not included in the above balances.

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23. Investments in associates
The significant associates of the group are shown in Note 43. The principal associate in 2009 is TNK-BP. Summarized financial information for the group s share of associates is set out below.

					$ million
			2009	2008	2007
	TNK-BP	**Other**	**Total**		
Sales and other operating revenues	**17,377**	**8,301**	**25,678**	11,709	9,855
Profit before interest and taxation	**3,178**	**811**	**3,989**	1,065	947
Finance costs	**220**	**19**	**239**	33	57
Profit before taxation	**2,958**	**792**	**3,750**	1,032	890
Taxation	**871**	**125**	**996**	234	193
Minority interest	**139**		**139**		
Profit for the year	**1,948**	**667**	**2,615**	798	697
Non-current assets	**13,437**	**4,573**	**18,010**	4,292	
Current assets	**4,205**	**1,887**	**6,092**	1,912	
Total assets	**17,642**	**6,460**	**24,102**	6,204	
Current liabilities	**3,122**	**1,640**	**4,762**	1,669	
Non-current liabilities	**4,797**	**2,277**	**7,074**	1,852	
Total liabilities	**7,919**	**3,917**	**11,836**	3,521	
Minority interest	**582**		**582**		
	9,141	**2,543**	**11,684**	2,683	
Group investment in associates					
Group share of net assets (as above)	**9,141**	**2,543**	**11,684**	2,683	
Loans made by group companies to associates		**1,279**	**1,279**	1,317	
	9,141	**3,822**	**12,963**	4,000	

Our investment in TNK-BP was reclassified from a jointly controlled entity to an associate with effect from 9 January 2009. See Note 22 for further information.
Transactions between the group and its associates are summarized below.

			$ million
Sales to associates	**2009**	2008	2007

Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas, employee services	**2,801**	**320**	3,248	219	697	60

Purchases from associates		**2009**		2008		2007
Product	**Purchases**	**Amount payable at 31 December**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
Crude oil and oil products, natural gas, transportation tariff	**5,110**	**614**	4,635	295	2,905	574

The terms of the outstanding balances receivable from associates are typically 30 to 45 days. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts.

The amounts receivable and payable at 31 December 2009, as shown in the table above, exclude $376 million due from and due to an intermediate associate which provides funding for our associate The Baku-Tbilisi-Ceyhan Pipeline Company. These balances are expected to be settled in cash throughout the period to 2015.

Dividends receivable at 31 December 2009 of $19 million are also excluded from the table above.

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24. Financial instruments and financial risk factors

The accounting classification of each category of financial instruments, and their carrying amounts, are set out below.

At 31 December	Note	Loans and receivables	Available-for-sale financial assets	At fair value through profit and loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	$ million 2009 Total carrying amount
Financial assets							
Other investments	**25**		**1,567**				**1,567**
Loans		**1,288**					**1,288**
Trade and other receivables	**27**	**31,016**					**31,016**
Derivative financial instruments	**31**			**7,960**	**972**		**8,932**
Cash and cash equivalents	**28**	**6,570**	**1,769**				**8,339**
Financial liabilities							
Trade and other payables	**30**					**(34,325)**	**(34,325)**
Derivative financial instruments	**31**			**(7,389)**	**(766)**		**(8,155)**
Accruals						**(6,905)**	**(6,905)**
Finance debt	**32**					**(34,627)**	**(34,627)**
		38,874	**3,336**	**571**	**206**	**(75,857)**	**(32,870)**

At 31 December	Note	Loans and receivables	Available-for-sale financial assets	At fair value through profit and loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	$ million 2008 Total carrying amount
Financial assets							
Other investments	25		855				855
Loans		1,163					1,163
Trade and other receivables	27	29,489					29,489
Derivative financial instruments	31			12,501	1,063		13,564

Cash and cash equivalents	28	5,609	2,588				8,197
Financial liabilities							
Trade and other payables	30					(33,140)	(33,140)
Derivative financial instruments	31			(13,173)	(2,075)		(15,248)
Accruals						(7,527)	(7,527)
Finance debt	32					(33,204)	(33,204)
		36,261	3,443	(672)	(1,012)	(73,871)	(35,851)

The fair value of finance debt is shown in Note 32. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

Financial risk factors

The group is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments including: market risks relating to commodity prices, foreign currency exchange rates, interest rates and equity prices; credit risk; and liquidity risk.

The group financial risk committee (GFRC) advises the group chief financial officer (CFO) who oversees the management of these risks. The GFRC is chaired by the CFO and consists of a group of senior managers including the group treasurer and the heads of the finance, tax and the integrated supply and trading functions. The purpose of the committee is to advise on financial risks and the appropriate financial risk governance framework for the group. The committee provides assurance to the CFO and the group chief executive (GCE), and via the GCE to the board, that the group s financial risk-taking activity is governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with group policies and group risk appetite.

The group s trading activities in the oil, natural gas and power markets are managed within the integrated supply and trading function, while activities in the financial markets are managed by the treasury function. All derivative activity is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control.

The integrated supply and trading function maintains formal governance processes that provide oversight of market risk associated with trading activity. These processes meet generally accepted industry practice and reflect the principles of the Group of Thirty Global Derivatives Study recommendations. A policy and risk committee monitors and validates limits and risk exposures, reviews incidents and validates risk-related policies, methodologies and procedures. A commitments committee approves value-at-risk delegations, the trading of new products, instruments and strategies and material commitments.

Notes on financial statements

24. Financial instruments and financial risk factors continued

In addition, the integrated supply and trading function undertakes derivative activity for risk management purposes under a separate control framework as described more fully below.

(a) Market risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of a business. The market price movements that the group is exposed to include oil, natural gas and power prices (commodity price risk), foreign currency exchange rates, interest rates, equity prices and other indices that could adversely affect the value of the group s financial assets, liabilities or expected future cash flows. The group enters into derivatives in a well established entrepreneurial trading operation. In addition, the group has developed a control framework aimed at managing the volatility inherent in certain of its natural business exposures. In accordance with this control framework the group enters into various transactions using derivatives for risk management purposes.

The group measures market risk exposure arising from its trading positions using value-at-risk techniques. These techniques are based on a variance/covariance model or a Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market prices over a 24-hour period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures and the history of one-day price movements, together with the correlation of these price movements. The value-at-risk measure is supplemented by stress testing and tail risk analysis.

The trading value-at-risk model is used for derivative financial instrument types such as: interest rate forward and futures contracts, swap agreements, options and swaptions; foreign exchange forward and futures contracts, swap agreements and options; and oil, natural gas and power price forwards, futures, swap agreements and options. Additionally, where physical commodities or non-derivative forward contracts are held as part of a trading position, they are also reflected in the value-at-risk model. For options, a linear approximation is included in the value-at-risk models when full revaluation is not possible.

The value-at-risk table does not incorporate any of the group s natural business exposures or any derivatives entered into to risk manage those exposures. Market risk exposure in respect of embedded derivatives is also not included in the value-at-risk table. Instead separate sensitivity analyses are disclosed below.

Value-at-risk limits are in place for each trading activity and for the group s trading activity in total. The board has delegated an overall limit of $100 million value at risk in support of this trading activity. The high and low values at risk indicated in the table below for each type of activity are independent of each other. Through the portfolio effect the high value at risk for the group as a whole is lower than the sum of the highs for the constituent parts. The potential movement in fair values is expressed to a 95% confidence interval. This means that, in statistical terms, one would expect to see a decrease in fair values greater than the trading value at risk on one occasion per month if the portfolio were left unchanged.

								$ million
Value at risk for 1 day at 95% confidence interval				**2009**				2008
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Group trading	**79**	**24**	**45**	**30**	76	20	37	69
Oil price trading	**75**	**9**	**29**	**12**	69	12	25	63
Natural gas price trading	**70**	**15**	**33**	**31**	50	12	24	23
Power price trading	**14**	**3**	**5**	**5**	14	3	7	4
Currency trading	**4**		**2**	**2**	4		2	
Interest rate trading	**7**		**3**	**3**	7		2	1

Other trading	**4**	**1**	**2**	**3**	5	1	2	2

The major components of market risk are commodity price risk, foreign currency exchange risk, interest rate risk and equity price risk, each of which is discussed below.

(i) Commodity price risk

The group s integrated supply and trading function uses conventional financial and commodity instruments and physical cargoes available in the related commodity markets. Oil and natural gas swaps, options and futures are used to mitigate price risk. Power trading is undertaken using a combination of over-the-counter forward contracts and other derivative contracts, including options and futures. This activity is on both a standalone basis and in conjunction with gas derivatives in relation to gas-generated power margin. In addition, NGLs are traded around certain US inventory locations using over-the-counter forward contracts in conjunction with over-the-counter swaps, options and physical inventories. Trading value-at-risk information in relation to these activities is shown in the table above.

As described above, the group also carries out risk management of certain natural business exposures using over-the-counter swaps and exchange futures contracts. Together with certain physical supply contracts that are classified as derivatives, these contracts fall outside of the value-at-risk framework. For these derivative contracts the sensitivity of the net fair value to an immediate 10% increase or decrease in all reference prices would have been $73 million at 31 December 2009 (2008 $90 million). This figure does not include any corresponding economic benefit or disbenefit that would arise from the natural business exposure which would be expected to offset the gain or loss on the over-the-counter swaps and exchange futures contracts mentioned above.

In addition, the group has embedded derivatives relating to certain natural gas contracts. The net fair value of these contracts was a liability of $1,331 million at 31 December 2009 (2008 liability of $1,867 million). Key information on the natural gas contracts is given below.

At 31 December	**2009**	2008
Remaining contract terms	**9 months to 8 years 9 months**	1 year 9 months to 9 years 9 months
Contractual/notional amount	**2,460 million therms**	3,585 million therms
Discount rate nominal risk free	**4.0%**	2.5%

Notes on financial statements

24. Financial instruments and financial risk factors continued
For these embedded derivatives the sensitivity of the net fair value to an immediate 10% favourable or adverse change in the key assumptions is as follows.

								$ million
At 31 December				**2009**				2008
	Gas price	**Oil price**	**Power price**	**Discount rate**	Gas price	Oil price	Power price	Discount rate
Favourable 10% change	**175**	**26**	**23**	**20**	291	81	27	16
Unfavourable 10% change	**(215)**	**(43)**	**(19)**	**(20)**	(289)	(81)	(27)	(16)

The sensitivities for risk management activity and embedded derivatives are hypothetical and should not be considered to be predictive of future performance. In addition, for the purposes of this analysis, in the above table, the effect of a variation in a particular assumption on the fair value of the embedded derivatives is calculated independently of any change in another assumption. In reality, changes in one factor may contribute to changes in another, which may magnify or counteract the sensitivities. Furthermore, the estimated fair values as disclosed should not be considered indicative of future earnings on these contracts.

(ii) Foreign currency exchange risk

Where the group enters into foreign currency exchange contracts for entrepreneurial trading purposes the activity is controlled using trading value-at-risk techniques as explained above. This activity is described as currency trading in the value at risk table above.

Since BP has global operations, fluctuations in foreign currency exchange rates can have significant effects on the group s reported results. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates and conversion differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the group s reported results. The main underlying economic currency of the group s cash flows is the US dollar. This is because BP s major product, oil, is priced internationally in US dollars. BP s foreign currency exchange management policy is to minimize economic and material transactional exposures arising from currency movements against the US dollar. The group co-ordinates the handling of foreign currency exchange risks centrally, by netting off naturally-occurring opposite exposures wherever possible, and then dealing with any material residual foreign currency exchange risks.

The group manages these exposures by constantly reviewing the foreign currency economic value at risk and managing such risk to keep the 12-month foreign currency value at risk below $200 million. At 31 December 2009, the foreign currency value at risk was $140 million
(2008 $70 million). At no point over the past three years did the value at risk exceed the maximum risk limit. The most significant exposures relate to capital expenditure commitments and other UK and European operational requirements, for which a hedging programme is in place and hedge accounting is claimed as outlined in Note 31.

For highly probable forecast capital expenditures the group locks in the US dollar cost of non-US dollar supplies by using currency forwards and futures. The main exposures are sterling, Canadian dollar, euro, Norwegian krone, Australian dollar, Korean won, and at 31 December 2009 open contracts were in place for $800 million sterling, $491 million Canadian dollar, $299 million euro, $240 million Norwegian krone, $215 million Australian dollar, $51 million Korean won and $41 million Singapore dollar capital expenditures maturing within six years, with over

65% of the deals maturing within two years (2008 $949 million sterling, $712 million Canadian dollar, $553 million euro, $392 million Norwegian krone, $303 million Australian dollar and $187 million Korean won capital expenditures maturing within seven years with over 65% of the deals maturing within two years).

For other UK, European, Canadian and Australian operational requirements the group uses cylinders and currency forwards to hedge the estimated exposures on a 12-month rolling basis. At 31 December 2009, the open positions relating to cylinders consisted of receive sterling, pay US dollar, purchased call and sold put options (cylinders) for $1,887 million (2008 $1,660 million); receive euro, pay US dollar cylinders for $1,716 million (2008 $1,612 million); receive Canadian dollar, pay US dollar cylinders for $300 million (2008 $250 million); and receive Australian dollar, pay US dollar cylinders for $297 million (2008 $455 million). At 31 December 2009 there were no open positions relating to currency forwards (2008 buy sterling, sell US dollar currency forwards for $816 million; buy euro, sell US dollar currency forwards for $141 million; buy Canadian dollar, sell US dollar, currency forwards for $50 million; and buy Australian dollar, sell US dollar currency forwards for $90 million).

In addition, most of the group s borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2009, the total foreign currency net borrowings not swapped into US dollars amounted to $465 million (2008 $1,037 million). Of this total, $113 million was denominated in currencies other than the functional currency of the individual operating unit being entirely Canadian dollars (2008 $92 million, being entirely Canadian dollars). It is estimated that a 10% change in the corresponding exchange rates would result in an exchange gain or loss in the income statement of $11 million (2008 $9 million).

(iii) Interest rate risk

Where the group enters into money market contracts for entrepreneurial trading purposes the activity is controlled using value-at-risk techniques as described above. This activity is described as interest rate trading in the value-at-risk table above.

BP is also exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments, principally finance debt.

While the group issues debt in a variety of currencies based on market opportunities, it uses derivatives to swap the debt to a US dollar floating rate exposure but in certain defined circumstances maintains a fixed rate exposure for a proportion of debt. The proportion of floating rate debt net of interest rate swaps at 31 December 2009 was 63% of total finance debt outstanding (2008 72%). The weighted average interest rate on finance debt at 31 December 2009 is 2% (2008 3%) and the weighted average maturity of fixed rate debt is four years (2008 three years).

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24. Financial instruments and financial risk factors continued
The group s earnings are sensitive to changes in interest rates on the floating rate element of the group s finance debt. If the interest rates applicable to floating rate instruments were to have increased by 1% on 1 January 2010, it is estimated that the group s profit before taxation for 2010 would decrease by approximately $219 million (2008 $239 million decrease in 2009). This assumes that the amount and mix of fixed and floating rate debt, including finance leases, remains unchanged from that in place at 31 December 2009 and that the change in interest rates is effective from the beginning of the year. Where the interest rate applicable to an instrument is reset during a quarter it is assumed that this occurs at the beginning of the quarter and remains unchanged for the rest of the year. In reality, the fixed/floating rate mix will fluctuate over the year and interest rates will change continually. Furthermore, the effect on earnings shown by this analysis does not consider the effect of any other changes in general economic activity that may accompany such an increase in interest rates.

(iv) Equity price risk

The group holds equity investments, typically made for strategic purposes, that are classified as non-current available-for-sale financial assets and are measured initially at fair value with changes in fair value recognized in other comprehensive income. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired. No impairment losses have been recognized in 2009 (2008 $546 million and 2007 nil) relating to listed non-current available-for-sale investments. For further information see Note 25.

At 31 December 2009, it is estimated that an increase of 10% in quoted equity prices would result in an immediate credit to other comprehensive income of $130 million (2008 $59 million credit to other comprehensive income), whilst a decrease of 10% in quoted equity prices would result in an immediate charge to other comprehensive income of $130 million (2008 $48 million charge to profit or loss and $11 million charge to other comprehensive income).

At 31 December 2009, 73% (2008 56%) of the carrying amount of non-current available-for-sale financial assets represented the group s stake in Rosneft, thus the group s exposure is concentrated on changes in the share price of this equity in particular.

(b) Credit risk

Credit risk is the risk that a customer or counterparty to a financial instrument will fail to perform or fail to pay amounts due causing financial loss to the group and arises from cash and cash equivalents, derivative financial instruments and deposits with financial institutions and principally from credit exposures to customers relating to outstanding receivables.

The group has a credit policy, approved by the CFO, that is designed to ensure that consistent processes are in place throughout the group to measure and control credit risk. Credit risk is considered as part of the risk-reward balance of doing business. On entering into any business contract the extent to which the arrangement exposes the group to credit risk is considered. Key requirements of the policy are formal delegated authorities to the sales and marketing teams to incur credit risk and to a specialized credit function to set counterparty limits; the establishment of credit systems and processes to ensure that counterparties are rated and limits set; and systems to monitor exposure against limits and report regularly on those exposures, and immediately on any excesses, and to track and report credit losses. The treasury function provides a similar credit risk management activity with respect to group-wide exposures to banks and other financial institutions.

In the current economic environment the group has placed increased emphasis on the management of credit risk. Policies and procedures were reviewed in 2008 and credit exposures arising from physical commodity and derivative transactions with banks and other counterparties have been reduced in 2008 and 2009, mainly through netting and collateral arrangements.

Before trading with a new counterparty can start, its creditworthiness is assessed and a credit rating is allocated that indicates the probability of default, along with a credit exposure limit. The assessment process takes into account all available qualitative and quantitative information about the counterparty and the group, if any, to which the counterparty belongs. The counterparty s business activities, financial resources and business risk management processes are taken into account in the assessment, to the extent that this information is publicly available or otherwise disclosed to BP by the counterparty, together with external credit ratings, if any, including ratings prepared by Moody s Investor Service and Standard & Poor s. Creditworthiness continues to be evaluated after transactions have been initiated and a watchlist of higher-risk counterparties is maintained.

The group does not aim to remove credit risk but expects to experience a certain level of credit losses. The group attempts to mitigate credit risk by entering into contracts that permit netting and allow for termination of the contract on the occurrence of certain events of default. Depending on the creditworthiness of the counterparty, the group may require collateral or other credit enhancements such as cash deposits or letters of credit and parent company guarantees. Trade receivables and payables, and derivative assets and liabilities, are presented on a net basis where unconditional netting arrangements are in place with counterparties and where there is an intent to settle amounts due on a net basis. The maximum credit exposure associated with financial assets is equal to the carrying amount. At 31 December 2009, the maximum credit exposure was $49,575 million (2008 $52,413 million). Collateral received and recognized in the balance sheet at the year-end was $549 million (2008 $1,121 million) and collateral held off balance sheet was $48 million (2008 $203 million). Credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2009 were $319 million (2008 $223 million) in respect of liabilities of jointly controlled entities and associates and $667 million (2008 $613 million) in respect of liabilities of other third parties.

Notwithstanding the processes described above, significant unexpected credit losses can occasionally occur. Exposure to unexpected losses increases with concentrations of credit risk that exist when a number of counterparties are involved in similar activities or operate in the same industry sector or geographical area, which may result in their ability to meet contractual obligations being impacted by changes in economic, political or other conditions. The group s principal customers, suppliers and financial institutions with which it conducts business are located throughout the world. In addition, these risks are managed by maintaining a group watchlist and aggregating multi-segment exposures to ensure that a material credit risk is not missed.

Reports are regularly prepared and presented to the GFRC that cover the group s overall credit exposure and expected loss trends, exposure by segment, and overall quality of the portfolio. The reports also include details of the largest counterparties by exposure level and expected loss, and details of counterparties on the group watchlist.

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24. Financial instruments and financial risk factors continued
Some mitigation of credit exposure is achieved by: netting arrangements; credit support agreements which require the counterparty to provide collateral or other credit risk mitigation; and credit insurance and other risk transfer instruments.

For the contracts comprising derivative financial instruments in an asset position at 31 December 2009, it is estimated that over 80%
(2008 over 80%) of the unmitigated credit exposure is to counterparties of investment grade credit quality.

Trade and other receivables of the group are analysed in the table below. By comparing the BP credit ratings to the equivalent external credit ratings, it is estimated that approximately 55-60% (2008 approximately 60-65%) of the unmitigated trade receivables portfolio exposure is of investment grade credit quality. With respect to the trade and other receivables that are neither impaired nor past due, there are no indications as of the reporting date that the debtors will not meet their payment obligations.

The group does not typically renegotiate the terms of trade receivables; however, if a renegotiation does take place, the outstanding balance is included in the analysis based on the original payment terms. There were no significant renegotiated balances outstanding at 31 December 2009 or 31 December 2008.

		$ million
Trade and other receivables at 31 December	**2009**	2008
Neither impaired nor past due	**29,426**	25,838
Impaired (net of valuation allowance)	**91**	73
Not impaired and past due in the following periods		
within 30 days	**808**	1,323
31 to 60 days	**151**	489
61 to 90 days	**76**	596
over 90 days	**464**	1,170
	31,016	29,489

The movement in the valuation allowance for trade receivables is set out below.

		$ million
Trade and other receivables at 31 December	**2009**	2008
At 1 January	**391**	406
Exchange adjustments	**12**	(32)
Charge for the year	**157**	191
Utilization	**(130)**	(174)
At 31 December	**430**	391

(c) Liquidity risk
Liquidity risk is the risk that suitable sources of funding for the group s business activities may not be available. The group s liquidity is managed centrally with operating units forecasting their cash and currency requirements to the central treasury function. Unless restricted by local regulations, subsidiaries pool their cash surpluses to treasury, which will then arrange to fund other subsidiaries requirements, or invest any net surplus in the market or arrange for

necessary external borrowings, while managing the group s overall net currency positions.

In managing its liquidity risk, the group has access to a wide range of funding at competitive rates through capital markets and banks. The group s treasury function centrally co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management. The group believes it has access to sufficient funding through the commercial paper markets and by using undrawn committed borrowing facilities to meet foreseeable borrowing requirements. At 31 December 2009, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,950 million, of which $4,550 million are in place through to the fourth quarter of 2011, unchanged from the position as at 31 December 2008. These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates.

The group has in place a European Debt Issuance Programme (DIP) under which the group may raise $20 billion of debt for maturities of one month or longer. At 31 December 2009, the amount drawn down against the DIP was $11,403 million (2008 $10,334 million). In addition, the group has in place an unlimited US Shelf Registration under which it may raise debt with maturities of one month or longer.

The group has long-term debt ratings of Aa1 (stable outlook) and AA (stable outlook), assigned respectively by Moody s and Standard and Poor s, unchanged from 2008.

Despite recent increased uncertainty in the financial markets, including a lack of liquidity for some borrowers, we have been able to issue $11 billion of long-term debt during 2009 and issue short-term commercial paper at competitive rates, as and when required. As an additional precautionary measure, we have increased and maintained the cash and cash equivalents held by the group to $8.3 billion at the end of 2009 and $8.2 billion at the end of 2008, compared with $3.6 billion at the end of 2007.

The amounts shown for finance debt in the table below include expected interest payments on borrowings and the future minimum lease payments with respect to finance leases.

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24. Financial instruments and financial risk factors continued
There are amounts included within finance debt that we show in the table below as due within one year to reflect the earliest contractual repayment dates but that are expected to be repaid over the maximum long-term maturity profiles of the contracts as described in Note 32. US Industrial Revenue/Municipal Bonds of $2,895 million (2008 $3,166 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 33 years (2008 1 to 40 years). The bondholders typically have the option to tender these bonds for repayment on interest reset dates; however, any bonds that are tendered are usually remarketed and BP has not experienced any significant repurchases. BP considers these bonds to represent long-term funding when internally assessing the maturity profile of its finance debt. Similar treatment is applied for loans associated with long-term gas supply contracts totalling $1,622 million (2008 $1,806 million) that mature within eight years.

The table also shows the timing of cash outflows relating to trade and other payables and accruals.

						$ million
			2009			2008
	Trade and other payables	**Accruals**	**Finance debt**	Trade and other payables	Accruals	Finance debt
Within one year	**31,413**	**6,202**	**9,790**	30,598	6,743	16,670
1 to 2 years	**1,059**	**231**	**6,861**	402	359	5,934
2 to 3 years	**1,089**	**106**	**5,359**	898	77	3,419
3 to 4 years	**566**	**78**	**5,528**	902	72	2,647
4 to 5 years	**67**	**49**	**3,151**	223	67	5,072
5 to 10 years	**85**	**163**	**5,723**	53	164	1,316
Over 10 years	**46**	**76**	**1,150**	64	45	1,050
	34,325	**6,905**	**37,562**	33,140	7,527	36,108

The group manages liquidity risk associated with derivative contracts, other than derivative hedging instruments, based on the expected maturities of both derivative assets and liabilities as indicated in Note 31. Management does not currently anticipate any cash flows that could be of a significantly different amount, or could occur earlier than the expected maturity analysis provided.

The table below shows cash outflows for derivative hedging instruments based upon contractual payment dates. The amounts reflect the maturity profile of the fair value liability where the instruments will be settled net, and the gross settlement amount where the pay leg of a derivative will be settled separately from the receive leg, as in the case of cross-currency interest rate swaps hedging non-US dollar finance debt. The swaps are with high investment-grade counterparties and therefore the settlement day risk exposure is considered to be negligible. Not shown in the table are the gross settlement amounts for the receive leg of derivatives that are settled separately from the pay leg, which amount to $7,999 million at 31 December 2009 (2008 $8,545 million) to be received on the same day as the related cash outflows.

		$ million
	2009	2008
Within one year	**2,826**	3,426

1 to 2 years	**1,395**	3,024
2 to 3 years	**1,669**	1,037
3 to 4 years	**1,349**	1,731
4 to 5 years	**1,104**	1,389
5 to 10 years	**322**	129
	8,665	10,736

The group has issued third-party guarantees, as described above under credit risk. These amounts represent the maximum exposure of the group, substantially all of which could be called within one year.

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25. Other investments

		$ million
	2009	2008
Listed	**1,296**	592
Unlisted	**271**	263
	1,567	855

Other investments comprise equity investments that have no fixed maturity date or coupon rate. These investments are classified as available-for-sale financial assets and as such are recorded at fair value with the gain or loss arising as a result of changes in fair value recorded directly in equity. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired.

The fair value of listed investments has been determined by reference to quoted market bid prices and as such are in level 1 of the fair value hierarchy. Unlisted investments are stated at cost less accumulated impairment losses and are in level 3 of the fair value hierarchy.

The most significant investment is the group s stake in Rosneft which had a fair value of $1,138 million at 31 December 2009 (2008 $483 million). The fair value gain arising on revaluation of this investment during 2009 has been recorded within other comprehensive income. In 2008, an impairment loss of $517 million was recognized in the income statement relating to the Rosneft investment (see Note 3). In 2009, impairment losses were incurred of $13 million (2008 $17 million) relating to unlisted investments and nil (2008 $29 million) relating to other listed investments.

26. Inventories

		$ million
	2009	2008
Crude oil	**6,237**	4,396
Natural gas	**105**	107
Refined petroleum and petrochemical products	**12,337**	9,318
	18,679	13,821
Supplies	**1,661**	1,588
	20,340	15,409
Trading inventories	**2,265**	1,412
	22,605	16,821
Cost of inventories expensed in the income statement	**163,772**	266,982

The inventory valuation at 31 December 2009 is stated net of a provision of $46 million (2008 $1,412 million) to write inventories down to their net realizable value. The net movement in the year in respect of inventory net realizable value provisions was $1,366 million credit (2008 $1,295 million charge).

27. Trade and other receivables

				$ million
		2009		2008
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**22,604**		22,869	
Amounts receivable from jointly controlled entities	**1,317**	**11**	1,035	
Amounts receivable from associates	**417**	**298**	219	
Other receivables	**4,949**	**1,420**	4,656	710
	29,287	**1,729**	28,779	710
Non-financial assets				
Other receivables	**244**		482	
	29,531	**1,729**	29,261	710

Trade and other receivables are predominantly non-interest bearing. See Note 24 for further information.

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28. Cash and cash equivalents

		$ million
	2009	2008
Cash at bank and in hand	**3,359**	3,442
Term bank deposits	**3,211**	2,167
Other cash equivalents	**1,769**	2,588
	8,339	8,197

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; term deposits of three months or less with banks and similar institutions; and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and have a maturity of three months or less from the date of acquisition. The carrying amounts of cash at bank and in hand and term bank deposits approximate their fair values. Substantially all of the other cash equivalents are categorized within level 1 of the fair value hierarchy.

Cash and cash equivalents at 31 December 2009 includes $1,095 million (2008 $2,133 million) that is restricted. This relates principally to amounts required to cover initial margins on trading exchanges.

See Note 24 for further information.

29. Valuation and qualifying accounts

						$ million
		2009		2008		2007
	Doubtful debts	**Fixed assets investments**	Doubtful debts	Fixed assets investments	Doubtful debts	Fixed assets investments
At 1 January	**391**	**935**	406	146	421	151
Charged to costs and expenses	**157**	**66**	191	647	175	158
Charged to other accounts[a]	**12**	**6**	(32)	143	34	2
Deductions	**(130)**	**(658)**	(174)	(1)	(224)	(165)
At 31 December	**430**	**349**	391	935	406	146

[a]Principally exchange adjustments.

Valuation and qualifying accounts are deducted in the balance sheet from the assets to which they apply.

30. Trade and other payables

				$ million
		2009		2008
	Current	**Non-current**	Current	Non-current
Financial liabilities				

Trade payables	**22,886**		20,129	
Amounts payable to jointly controlled entities	**304**	**2,419**	292	2,255
Amounts payable to associates	**692**	**298**	295	
Other payables	**7,531**	**195**	9,882	287
	31,413	**2,912**	30,598	2,542
Non-financial liabilities				
Production and similar taxes	**757**	**286**	445	538
Other payables	**3,034**		2,601	
	3,791	**286**	3,046	538
	35,204	**3,198**	33,644	3,080

Trade and other payables are predominantly interest free. See Note 24 for further information.

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31. Derivative financial instruments
An outline of the group s financial risks and the objectives and policies pursued in relation to those risks is set out in Note 24.

In the normal course of business the group enters into derivative financial instruments (derivatives) to manage its normal business exposures in relation to commodity prices, foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt, consistent with risk management policies and objectives. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts.

IAS 39 prescribes strict criteria for hedge accounting, whether as a cash flow or fair value hedge or a hedge of a net investment in a foreign operation, and requires that any derivative that does not meet these criteria should be classified as held for trading and fair valued, with gains and losses recognized in the income statement.

The fair values of derivative financial instruments at 31 December are set out below.

				$ million
		2009		2008
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**318**	**(226)**	278	(273)
Oil price derivatives	**1,140**	**(1,191)**	3,813	(3,523)
Natural gas price derivatives	**5,636**	**(3,960)**	6,945	(6,113)
Power price derivatives	**682**	**(497)**	978	(904)
Other derivatives	**47**	**(47)**	90	(96)
	7,823	**(5,921)**	12,104	(10,909)
Embedded derivative commodity contracts	**137**	**(1,468)**	397	(2,264)
Cash flow hedges				
Currency forwards, futures and cylinders	**182**	**(114)**	120	(1,175)
Cross-currency interest rate swaps	**44**	**(298)**	109	(558)
	226	**(412)**	229	(1,733)
Fair value hedges				
Currency forwards, futures and swaps	**490**	**(232)**	465	(342)
Interest rate swaps	**256**	**(122)**	367	
	746	**(354)**	832	(342)
Hedges of net investments in foreign operations			2	
	8,932	**(8,155)**	13,564	(15,248)

Of which current	**4,967**	**(4,681)**	8,510	(8,977)
non-current	**3,965**	**(3,474)**	5,054	(6,271)

Derivatives held for trading

The group maintains active trading positions in a variety of derivatives. The contracts may be entered into for risk management purposes, to satisfy supply requirements or for entrepreneurial trading. Certain contracts are classified as held for trading, regardless of their original business objective, and are recognized at fair value with changes in fair value recognized in the income statement. Trading activities are undertaken by using a range of contract types in combination to create incremental gains by arbitraging prices between markets, locations and time periods. The net of these exposures is monitored using market value-at-risk techniques as described in Note 24.

The following tables show further information on the fair value of derivatives and other financial instruments held for trading purposes. Derivative assets held for trading have the following fair values and maturities.

							$ million **2009**
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**162**	**83**	**33**	**22**	**16**	**2**	**318**
Oil price derivatives	**814**	**136**	**69**	**59**	**44**	**18**	**1,140**
Natural gas price derivatives	**2,958**	**1,059**	**582**	**354**	**186**	**497**	**5,636**
Power price derivatives	**496**	**139**	**32**	**12**	**3**		**682**
Other derivatives	**47**						**47**
	4,477	**1,417**	**716**	**447**	**249**	**517**	**7,823**

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31. Derivative financial instruments continued

$ million 2008

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	53	90	67	37	20	11	278
Oil price derivatives	3,368	353	61	11	11	9	3,813
Natural gas price derivatives	3,940	1,090	545	436	271	663	6,945
Power price derivatives	688	256	31	1	2		978
Other derivatives	90						90
	8,139	1,789	704	485	304	683	12,104

Derivative liabilities held for trading have the following fair values and maturities.

$ million **2009**

	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**(110)**	**(58)**	**(20)**	**(32)**	**(4)**	**(2)**	**(226)**
Oil price derivatives	**(1,083)**	**(67)**	**(29)**	**(11)**	**(1)**		**(1,191)**
Natural gas price derivatives	**(2,381)**	**(607)**	**(248)**	**(222)**	**(78)**	**(424)**	**(3,960)**
Power price derivatives	**(335)**	**(109)**	**(39)**	**(11)**	**(3)**		**(497)**
Other derivatives	**(47)**						**(47)**
	(3,956)	**(841)**	**(336)**	**(276)**	**(86)**	**(426)**	**(5,921)**

$ million 2008

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(257)		(2)	(1)	(13)		(273)
Oil price derivatives	(3,001)	(458)	(36)	(18)	(9)	(1)	(3,523)

Natural gas price derivatives	(3,484)	(987)	(438)	(310)	(283)	(611)	(6,113)
Power price derivatives	(722)	(159)	(18)	(4)	(1)		(904)
Other derivatives	(95)	(1)					(96)
	(7,559)	(1,605)	(494)	(333)	(306)	(612)	(10,909)

If at inception of a contract the valuation cannot be supported by observable market data, any gain or loss determined by the valuation methodology is not recognized in the income statement but is deferred on the balance sheet and is commonly known as day-one profit or loss . This deferred gain or loss is recognized in the income statement over the life of the contract until substantially all of the remaining contract term can be valued using observable market data at which point any remaining deferred gain or loss is recognized in the income statement. Changes in valuation from this initial valuation are recognized immediately through the income statement.

The following table shows the changes in the day-one profits and losses deferred on the balance sheet.

				$ million
		2009		2008
	Oil price	**Natural gas price**	Oil price	Natural gas price
Fair value of contracts not recognized through the income statement at 1 January	**32**	**83**		36
Fair value of new contracts at inception not recognized in the income statement		**(14)**	66	49
Fair value recognized in the income statement	**(11)**	**(36)**	(34)	(2)
Fair value of contracts not recognized through the income statement at 31 December	**21**	**33**	32	83

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Notes on financial statements

31. Derivative financial instruments continued

The following table shows the fair value of derivative assets and derivative liabilities held for trading, analysed by maturity period and by methodology of fair value estimation.

IFRS 7 Financial Instruments: Disclosures sets out a fair value hierarchy which consists of three levels that describe the methodology of estimation as follows:

Level 1 using quoted prices in active markets for identical assets or liabilities.

Level 2 using inputs for the asset or liability, other than quoted prices, that are observable either directly (i.e. as prices) or indirectly (i.e. derived from prices).

Level 3 using inputs for the asset or liability that are not based on observable market data such as prices based on internal models or other valuation methods.

This information is presented on a gross basis, that is, before netting by counterparty.

							$ million 2009
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Fair value of derivative assets							
Level 1	**163**	**76**	**23**	**17**	**10**	**1**	**290**
Level 2	**9,544**	**2,182**	**915**	**357**	**146**		**13,144**
Level 3	**264**	**188**	**162**	**148**	**128**	**527**	**1,417**
	9,971	**2,446**	**1,100**	**522**	**284**	**528**	**14,851**
Less: netting by counterparty	**(5,494)**	**(1,029)**	**(384)**	**(75)**	**(35)**	**(11)**	**(7,028)**
	4,477	**1,417**	**716**	**447**	**249**	**517**	**7,823**
Fair value of derivative liabilities							
Level 1	**(95)**	**(39)**	**(14)**	**(24)**		**(1)**	**(173)**
Level 2	**(9,086)**	**(1,681)**	**(597)**	**(234)**	**(47)**		**(11,645)**
Level 3	**(269)**	**(150)**	**(109)**	**(93)**	**(74)**	**(436)**	**(1,131)**
	(9,450)	**(1,870)**	**(720)**	**(351)**	**(121)**	**(437)**	**(12,949)**
Less: netting by counterparty	**5,494**	**1,029**	**384**	**75**	**35**	**11**	**7,028**

	(3,956)	**(841)**	**(336)**	**(276)**	**(86)**	**(426)**	**(5,921)**
Net fair value	**521**	**576**	**380**	**171**	**163**	**91**	**1,902**

							$ million 2008
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of derivative assets							
Level 1	40	43	30	7	6	2	128
Level 2	19,737	3,477	871	508	225	56	24,874
Level 3	687	196	148	140	137	672	1,980
	20,464	3,716	1,049	655	368	730	26,982
Less: netting by counterparty	(12,325)	(1,927)	(345)	(170)	(64)	(47)	(14,878)
	8,139	1,789	704	485	304	683	12,104
Fair value of derivative liabilities							
Level 1	(227)		(2)		(13)		(242)
Level 2	(19,106)	(3,345)	(683)	(356)	(217)	(27)	(23,734)
Level 3	(551)	(187)	(154)	(147)	(140)	(632)	(1,811)
	(19,884)	(3,532)	(839)	(503)	(370)	(659)	(25,787)
Less: netting by counterparty	12,325	1,927	345	170	64	47	14,878
	(7,559)	(1,605)	(494)	(333)	(306)	(612)	(10,909)
Net fair value	580	184	210	152	(2)	71	1,195

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31. Derivative financial instruments continued
The following table shows the changes during the year in the net fair value of derivatives held for trading purposes within level 3 of the fair value hierarchy.

						$ million
	Currency	**Oil price**	**Natural gas price**	**Power price**	**Other**	**Total**
Net fair value of contracts at 1 January 2009	**3**	**149**	**17**			**169**
Gains (losses) recognized in the income statement	**(1)**	**205**	**91**		**(1)**	**294**
Settlements		**(91)**	**(5)**			**(96)**
Purchases				**1**		**1**
Sales				**(2)**	**1**	**(1)**
Transfers out of level 3	**(2)**	**(50)**	**(4)**			**(56)**
Transfers in to level 3		**2**	**(25)**			**(23)**
Exchange adjustments			**(2)**			**(2)**
Net fair value of contracts at 31 December 2009		**215**	**72**	**(1)**		**286**

						$ million
	Currency	Oil price	Natural gas price	Power price	Other	Total
Net fair value of contracts at 1 January 2008	(17)	1	(67)	(1)		(84)
Gains recognized in the income statement	8	148	160			316
Settlements		18	3	1		22
Transfers out of level 3	12	(25)	(79)			(92)
Transfers in to level 3		7	3			10
Exchange adjustments			(3)			(3)
Net fair value of contracts at 31 December 2008	3	149	17			169

The amount recognized in the income statement for the year relating to level 3 derivatives still held at 31 December 2009 was a $278 million gain (2008 $199 million gain relating to derivatives still held at 31 December 2008).

Gains and losses relating to derivative contracts are included either within sales and other operating revenues or within purchases in the income statement depending upon the nature of the activity and type of contract involved. The contract types treated in this way include futures, options, swaps and certain forward sales and forward purchases contracts. Gains or losses arise on contracts entered into for risk management purposes, optimization activity and entrepreneurial trading. They also arise on certain contracts that are for normal procurement or sales activity for the group but that are required to be fair valued under accounting standards. Also included within sales and other operating revenues are gains and losses on inventory held for trading purposes. The total amount relating to all of these items was a net gain of $3,735 million (2008 $6,721 million net gain and 2007 $376 million net gain).

Embedded derivatives

Prior to the development of an active gas trading market, UK gas contracts were priced using a basket of available price indices, primarily relating to oil products, power and inflation. After the development of an active UK gas market, certain contracts were entered into or renegotiated using pricing formulae not directly related to gas prices, for example, oil product and power prices. In these circumstances, pricing formulae have been determined to be derivatives, embedded within the overall contractual arrangements that are not clearly and closely related to the underlying commodity. The resulting fair value relating to these contracts is recognized on the balance sheet with gains or losses recognized in the income statement.

All the embedded derivatives are valued using inputs that include price curves for each of the different products that are built up from active market pricing data. Where necessary, these are extrapolated to the expiry of the contracts (the last of which is in 2018) using all available external pricing information. Additionally, where limited data exists for certain products, prices are interpolated using historic and long-term pricing relationships.

Embedded derivative assets have the following fair values and maturities.

							$ million **2009**
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Commodity price embedded derivatives	**134**					**3**	**137**

							$ million 2008
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Commodity price embedded derivatives	50	116	75	45	36	75	397

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31. Derivative financial instruments continued
Embedded derivative liabilities have the following fair values and maturities.

							$ million **2009**
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Commodity price embedded derivatives	**(154)**	**(236)**	**(231)**	**(227)**	**(232)**	**(388)**	**(1,468)**

							$ million 2008
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Commodity price embedded derivatives	(404)	(322)	(365)	(303)	(271)	(599)	(2,264)

The following table shows the fair value of embedded derivative assets and liabilities analysed by maturity period and by methodology of fair value estimation.

							$ million **2009**
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Fair value of embedded derivative assets							
Level 1							
Level 2							
Level 3	**134**					**3**	**137**
	134					**3**	**137**

Fair value of embedded derivative liabilities							
Level 1							
Level 2							
Level 3	**(154)**	**(236)**	**(231)**	**(227)**	**(232)**	**(388)**	**(1,468)**
	(154)	**(236)**	**(231)**	**(227)**	**(232)**	**(388)**	**(1,468)**
Net fair value	**(20)**	**(236)**	**(231)**	**(227)**	**(232)**	**(385)**	**(1,331)**

							$ million 2008
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of embedded derivative assets							
Level 1							
Level 2	35						35
Level 3	15	116	75	45	36	75	362
	50	116	75	45	36	75	397
Fair value of embedded derivative liabilities							
Level 1							
Level 2	(10)						(10)
Level 3	(394)	(322)	(365)	(303)	(271)	(599)	(2,254)
	(404)	(322)	(365)	(303)	(271)	(599)	(2,264)
Net fair value	(354)	(206)	(290)	(258)	(235)	(524)	(1,867)

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31. Derivative financial instruments continued

The following table shows the changes during the year in the net fair value of embedded derivatives within level 3 of the fair value hierarchy.

				$ million
	2009			2008
	Commodity price	Commodity price	Interest rate	Total
Net fair value of contracts at 1 January	**(1,892)**	(2,146)	(33)	(2,179)
Settlements	**221**	414	38	452
Gains (losses) recognized in the income statement[a]	**535**	(1,011)	(5)	(1,016)
Exchange adjustments	**(195)**	851		851
Net fair value of contracts at 31 December	**(1,331)**	(1,892)		(1,892)

[a] The amount for gains (losses) recognized in the income statement for 2009 includes a loss of $224 million arising as a result of refinements in the modelling and valuation methods used for these contracts.

The amount recognized in the income statement for the year relating to level 3 embedded derivatives still held at 31 December 2009 was a $347 million gain (2008 $985 million loss relating to embedded derivatives still held at 31 December 2008).

The fair value gain (loss) on embedded derivatives is shown below.

			$ million
	2009	2008	2007
Commodity price embedded derivatives	**607**	(106)	
Interest rate embedded derivatives		(5)	(7)
Fair value gain (loss)	**607**	(111)	(7)

Cash flow hedges

At 31 December 2009, the group held currency forwards and futures contracts and cylinders that were being used to hedge the foreign currency risk of highly probable forecast transactions, as well as cross-currency interest rate swaps to fix the US dollar interest rate and US dollar redemption value, with matching critical terms on the currency leg of the swap with the underlying non-US dollar debt issuance. Note 24 outlines the management of risk aspects for currency and interest rate risk. For cash flow hedges the group only claims hedge accounting for the intrinsic value on the currency with any fair value attributable to time value taken immediately to the income statement. There were no highly probable transactions for which hedge accounting has been claimed that have not occurred and no significant element of hedge ineffectiveness requiring recognition in the income statement. For cash flow hedges the pre-tax amount removed from equity during the period and included in the income statement is a loss of $366 million (2008 loss of $45 million and 2007 gain of $74 million). Of this, a loss of $332 million is included in production and manufacturing expenses (2008 $1 million loss and 2007 $143 million gain) and a loss of $34 million is included in finance costs (2008 $44 million loss and 2007 $69 million loss). The amount removed from equity during the period and included in the carrying amount of non-financial assets was a loss of $136 million (2008 $38 million gain and 2007 $40 million gain).

The amounts retained in equity at 31 December 2009 are expected to mature and affect the income statement by a $146 million gain in 2010, a loss of $26 million in 2011 and a loss of $65 million in 2012 and beyond.

Fair value hedges

At 31 December 2009, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk on fixed rate debt issued by the group. The effectiveness of each hedge relationship is quantitatively assessed and demonstrated to continue to be highly effective. The loss on the hedging derivative instruments taken to the income statement in 2009 was $98 million (2008 $2 million gain and 2007 $334 million gain) offset by a gain on the fair value of the finance debt of $117 million (2008 $20 million loss and 2007 $327 million loss).

The interest rate and cross-currency interest rate swaps have an average maturity of four to five years, (2008 three to four years) and are used to convert sterling, euro, Swiss franc, Australian dollar, Japanese yen and Hong Kong dollar denominated borrowings into US dollar floating rate debt. Note 24 outlines the group s approach to interest rate risk management.

Hedges of net investments in foreign operations

The group held currency swap contracts as a hedge of a long-term investment in a UK subsidiary that expired in 2009. At 31 December 2008, the hedge had a fair value of $2 million and the loss on the hedge recognized in equity in 2008 was $38 million (2007 $67 million loss). US dollars had been sold forward for sterling purchased and matched the underlying liability with no significant ineffectiveness reflected in the income statement.

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32. Finance debt

						$ million
			2009			2008
	Within 1 year[a]	**After 1 year**	**Total**	Within 1 year [a]	After 1 year	Total
Borrowings	**9,018**	**25,020**	**34,038**	15,647	16,937	32,584
Net obligations under finance leases	**91**	**498**	**589**	93	527	620
	9,109	**25,518**	**34,627**	15,740	17,464	33,204

[a] Amounts due within one year include current maturities of long-term debt and borrowings that are expected to be repaid later than the earliest contractual repayment dates of within one year. US Industrial Revenue/Municipal Bonds of $2,895 million (2008 $3,166 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 33 years (2008 1 to 40 years). The bondholders typically have the option to tender these bonds for repayment on interest reset dates; however, any bonds that are tendered are usually remarketed and BP has not experienced any significant repurchases. BP considers these bonds to represent long-term funding when internally assessing the maturity profile of its finance debt. Similar treatment is applied for loans associated with long-term gas supply contracts totalling $1,622 million (2008 $1,806 million) that mature within eight years.

The following table shows, by major currency, the group s finance debt at 31 December and the weighted average interest rates achieved at those dates through a combination of borrowings and derivative financial instruments entered into to manage interest rate and currency exposures.

			Fixed rate debt		**Floating rate debt**	**Total**
	Weighted average interest rate %	**Weighted average time for which rate is fixed Years**	**Amount $ million**	**Weighted average interest rate %**	**Amount $ million**	**Amount $ million**
						2009
US dollar	**4**	**4**	**12,525**	**1**	**20,566**	**33,091**
Euro	**4**	**2**	**63**	**2**	**1,199**	**1,262**
Other currencies	**6**	**14**	**171**	**3**	**103**	**274**

			12,759		**21,868**	**34,627**

						2008
US dollar	5	3	9,005	2	22,116	31,121
Sterling				6	21	21
Euro	4	3	74	4	1,330	1,404
Other currencies	7	10	216	7	442	658
			9,295		23,909	33,204

Finance leases
The group uses finance leases to acquire property, plant and equipment. These leases have terms of renewal but no purchase options and escalation clauses. Renewals are at the option of the lessee. Future minimum lease payments under finance leases are set out below.

		$ million
	2009	2008
Future minimum lease payments payable within		
1 year	**109**	116
2 to 5 years	**329**	361
Thereafter	**407**	439
	845	916
Less finance charges	**256**	296
Net obligations	**589**	620
Of which payable within 1 year	**91**	93
payable within 2 to 5 years	**202**	234
payable thereafter	**296**	293

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32. Finance debt continued

Fair values

The estimated fair value of finance debt is shown in the table below together with the carrying amount as reflected in the balance sheet.

Long-term borrowings in the table below include the portion of debt that matures in the year from 31 December 2009, whereas in the balance sheet the amount would be reported within current liabilities.

The carrying amount of the group s short-term borrowings, comprising mainly commercial paper, bank loans, overdrafts and US Industrial Revenue/Municipal Bonds, approximates their fair value. The fair value of the group s long-term borrowings and finance lease obligations is estimated using quoted prices or, where these are not available, discounted cash flow analyses based on the group s current incremental borrowing rates for similar types and maturities of borrowing.

				$ million
		2009		2008
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**5,144**	**5,144**	9,913	9,913
Long-term borrowings	**29,918**	**28,894**	23,239	22,671
Net obligations under finance leases	**599**	**589**	638	620
Total finance debt	**35,661**	**34,627**	33,790	33,204

See Note 24 for further information.

33. Capital disclosures and analysis of changes in net debt

The group defines capital as the total equity of the group. The group s objective for managing capital is to deliver competitive, secure and sustainable returns to maximize long-term shareholder value. BP is not subject to any externally-imposed capital requirements.

The group s approach to managing capital is set out in its financial framework. The group aims to strike the right balance for shareholders, between current returns via the dividend, sustained investment for long-term growth and maintaining a prudent gearing level. At the beginning of 2008, the group rebalanced distributions away from share buybacks in favour of dividends. During 2009, the company did not repurchase any of its own shares.

The group monitors capital on the basis of the net debt ratio, that is, the ratio of net debt to net debt plus equity. Net debt is calculated as gross finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is claimed, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. BP uses these measures to provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total. The net debt ratio enables investors to see how significant net debt is relative to equity from shareholders. The derivatives are reported on the balance sheet within the headings Derivative financial instruments . All components of equity are included in the denominator of the calculation. We believe that a net debt ratio in the range 20-30% provides an efficient capital structure and an appropriate level of financial flexibility.

At 31 December 2009 the net debt ratio was 20% (2008 21%).

At 31 December	**2009**	$ million 2008
Gross debt	**34,627**	33,204
Less: Cash and cash equivalents	**8,339**	8,197
Less: Fair value asset (liability) of hedges related to finance debt	**127**	(34)
Net debt	**26,161**	25,041
Equity	**102,113**	92,109
Net debt ratio	**20%**	21%

An analysis of changes in net debt is provided below.

	2009					$ million 2008
Movement in net debt	**Finance debt[a]**	**Cash and cash equivalents**	**Net debt**	Finance debt[a]	Cash and cash equivalents	Net debt
At 1 January	**(33,238)**	**8,197**	**(25,041)**	(30,379)	3,562	(26,817)
Exchange adjustments	**(60)**	**110**	**50**	102	(184)	(82)
Net cash flow	**(1,141)**	**32**	**(1,109)**	(2,825)	4,819	1,994
Other movements	**(61)**		**(61)**	(136)		(136)
At 31 December	**(34,500)**	**8,339**	**(26,161)**	(33,238)	8,197	(25,041)

[a] Including fair value of associated derivative financial instruments.

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34. Provisions

					$ million
	Decommissioning	**Environmental**	**Litigation**	**Other**	**Total**
At 1 January 2009	**8,418**	**1,691**	**1,446**	**2,098**	**13,653**
Exchange adjustments	**398**	**15**	**22**	**29**	**464**
New or increased provisions	**169**	**588**	**302**	**1,256**	**2,315**
Write-back of unused provisions		**(259)**	**(99)**	**(228)**	**(586)**
Unwinding of discount	**184**	**32**	**15**	**16**	**247**
Change in discount rate	**324**	**18**	**(35)**	**8**	**315**
Utilization	**(383)**	**(308)**	**(574)**	**(361)**	**(1,626)**
Deletions	**(90)**	**(58)**	**(1)**	**(3)**	**(152)**
At 31 December 2009	**9,020**	**1,719**	**1,076**	**2,815**	**14,630**
Of which expected to be incurred within 1 year	**287**	**368**	**433**	**572**	**1,660**
expected to be incurred in more than 1 year	**8,733**	**1,351**	**643**	**2,243**	**12,970**

					$ million
	Decommissioning	Environmental	Litigation	Other	Total
At 1 January 2008	9,501	2,107	1,737	1,750	15,095
Exchange adjustments	(1,208)	(45)	(1)	(106)	(1,360)
New or increased provisions	327	270	886	1,173	2,656
Write-back of unused provisions		(107)	(383)	(130)	(620)
Unwinding of discount	202	43	22	20	287
Utilization	(402)	(512)	(815)	(609)	(2,338)
Deletions	(2)	(65)			(67)
At 31 December 2008	8,418	1,691	1,446	2,098	13,653
Of which expected to be incurred within 1 year	322	418	521	284	1,545
expected to be incurred in more than 1 year	8,096	1,273	925	1,814	12,108

The group makes full provision for the future cost of decommissioning oil and natural gas production facilities and related pipelines on a discounted basis on the installation of those facilities. The provision for the costs of decommissioning these production facilities and pipelines at the end of their economic lives has been estimated using existing technology, at current prices or long-term assumptions, depending on the expected timing of the activity, and discounted using a real discount rate of 1.75% (2008 2.0%). These costs are generally expected to be incurred over the next 30 years. While the provision is based on the best estimate of future costs and the economic lives of the facilities and pipelines, there is uncertainty regarding both the amount and timing of incurring these costs.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provision for environmental liabilities has been estimated using existing technology, at current prices and discounted using a real discount rate of 1.75% (2008 2.0%). The majority of these costs are expected to be incurred over the next 10 years. The extent and cost of future remediation programmes are inherently difficult to estimate. They depend on the scale of any possible contamination, the timing and extent of corrective actions, and also the group s share of the liability.

The litigation category includes provisions for matters related to, for example, commercial disputes, product liability, and allegations of exposures of third parties to toxic substances. Included within the other category at 31 December 2009 are provisions for deferred employee compensation of $789 million (2008 $792 million) and for expected rental shortfalls on surplus properties of $246 million (2008 $251 million). These provisions are discounted using either a nominal discount rate of 4.0% (2008 2.5%) or a real discount rate of 1.75% (2008 2.0%), as appropriate.

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35. Pensions and other post-retirement benefits
Most group companies have pension plans, the forms and benefits of which vary with conditions and practices in the countries concerned. Pension benefits may be provided through defined contribution plans (money purchase schemes) or defined benefit plans (final salary and other types of schemes with committed pension payments). For defined contribution plans, retirement benefits are determined by the value of funds arising from contributions paid in respect of each employee. For defined benefit plans, retirement benefits are based on such factors as the employees pensionable salary and length of service. Defined benefit plans may be externally funded or unfunded. The assets of funded plans are generally held in separately administered trusts.

In particular, the primary pension arrangement in the UK is a funded final salary pension plan under which retired employees draw the majority of their benefit as an annuity. During 2009, BP announced that, with effect from 1 April 2010, it will close its UK plan to new joiners other than some of those joining the North Sea SPU. The plan will remain open to those employees who joined BP on or before 31 March 2010.

In the US, a range of retirement arrangements are provided. These include a funded final salary pension plan for certain heritage employees and a cash balance arrangement for new hires. Retired US employees typically take their pension benefit in the form of a lump sum payment. US employees are also eligible to participate in a defined contribution (401k) plan in which employee contributions are matched with company contributions.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2009, contributions of $9 million (2008 $6 million and 2007 $524 million) and $795 million (2008 $362 million and 2007 $97 million) were made to the UK plans and US plans respectively. In addition, contributions of $204 million (2008 $130 million and 2007 $127 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2010 is expected to be approximately $1,000 million, and includes contributions in all countries that we expect to be required to make by law or under contractual agreements as well as an allowance for discretionary funding.

Certain group companies, principally in the US, provide post-retirement healthcare and life insurance benefits to their retired employees and dependants. The entitlement to these benefits is usually based on the employee remaining in service until retirement age and completion of a minimum period of service. The plans are funded to a limited extent.

The obligation and cost of providing pensions and other post-retirement benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2009. The group s principal plans are subject to a formal actuarial valuation every three years in the UK, with valuations being required more frequently in many other countries. The most recent formal actuarial valuation of the UK pension plans was as at 31 December 2008.

The material financial assumptions used for estimating the benefit obligations of the various plans are set out below. The assumptions are reviewed by management at the end of each year, and are used to evaluate accrued pension and other post-retirement benefits at 31 December. The same assumptions are used to determine pension and other post-retirement benefit expense for the following year, that is, the assumptions at 31 December 2009 are used to determine the pension liabilities at that date and the pension expense for 2010.

									%
Financial assumptions			UK			US			Other
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Discount rate for pension plan liabilities	**5.8**	6.3	5.7	**5.4**	6.3	6.1	**5.8**	5.7	5.6
	n/a	n/a	n/a	**5.8**	6.2	6.4	**n/a**	n/a	n/a

Discount rate for other post-retirement benefit plans									
Rate of increase in salaries	**5.3**	4.9	5.1	**4.2**	2.2	4.2	**3.8**	3.5	3.7
Rate of increase for pensions in payment	**3.4**	3.0	3.2				**1.8**	1.7	1.8
Rate of increase in deferred pensions	**3.4**	3.0	3.2				**1.2**	1.0	1.2
Inflation	**3.4**	3.0	3.2	**2.4**	0.4	2.4	**2.3**	2.0	2.2

Our discount rate assumptions are based on third-party AA corporate bond indices and for our largest plans in the UK, US and Germany we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumptions for our UK and US plans are based on the difference between the yields on index-linked and fixed-interest long-term government bonds. In other countries we use either this approach, or the central bank inflation target, or advice from the local actuary depending on the information that is available to us. The inflation assumptions are used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions where there is such an increase.

Our assumptions for the rate of increase in salaries are based on our inflation assumption plus an allowance for expected long-term real salary growth. These include allowance for promotion-related salary growth, of between 0.3% and 0.4% depending on country. In addition to the financial assumptions, we regularly review the demographic and mortality assumptions.

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35. Pensions and other post-retirement benefits continued

The mortality assumptions reflect best practice in the countries in which we provide pensions, and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. BP s most substantial pension liabilities are in the UK, the US and Germany where our mortality assumptions are as follows:

									Years
Mortality assumptions			UK			US			Germany
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Life expectancy at age 60 for a male currently aged 60	**26.0**	25.9	24.0	**24.6**	24.4	24.3	**23.2**	23.0	22.4
Life expectancy at age 60 for a male currently aged 40	**29.0**	28.9	25.1	**26.1**	25.9	25.8	**26.1**	25.9	25.3
Life expectancy at age 60 for a female currently aged 60	**28.6**	28.5	26.9	**26.3**	26.1	26.1	**27.8**	27.6	27.0
Life expectancy at age 60 for a female currently aged 40	**31.5**	31.4	27.9	**27.2**	27.0	27.0	**30.4**	30.3	29.7

Our assumptions for future US healthcare cost trend rate reflect the rate of actual cost increases seen in recent years for the initial trend rate, and the ultimate trend rate reflects our long-term expectations based on past healthcare cost inflation seen over a longer period of time. The assumed future US healthcare cost trend rate is as follows:

			%
	2009	2008	2007
Initial US healthcare cost trend rate	**8.2**	8.6	9.0
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2017**	2015	2013

Pension plan assets are generally held in trusts. The primary objective of the trusts is to accumulate pools of assets sufficient to meet the obligations of the various plans. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

A significant proportion of the assets are held in equities, owing to a higher expected level of return over the long term with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified. The long-term asset allocation policy for the major plans is as follows:

Asset category	Policy range %
Total equity	45-75
Bonds/cash	17.5-50
Property/real estate	0-10

Some of the group s pension plans use derivative financial instruments as part of their asset mix and to manage the level of risk. The group s main pension plans do not invest directly in either securities or property/real estate of the company or of any subsidiary.

Return on asset assumptions reflect the group s expectations built up by asset class and by plan. The group s expectation is derived from a combination of historical returns over the long term and the forecasts of market professionals. Our assumption for return on equities is based on a long-term view, and the size of the resulting equity risk premium over government bond yields is reviewed each year for reasonableness. Our assumption for return on bonds reflects the portfolio mix of government fixed-interest, index-linked and corporate bonds.

Notes on financial statements

35. Pensions and other post-retirement benefits continued

The expected long-term rates of return and market values of the various categories of asset held by the defined benefit plans at 31 December are set out below. The market values shown include the effects of derivative financial instruments. The amounts classified as equities include investments in companies listed on stock exchanges as well as unlisted investments. The market value of unlisted investments at 31 December 2009 was $2,956 million (2008 $2,819 million and 2007 $2,491 million). The market value of pension assets at the end of 2009 is higher than at the end of 2008 due to a rise in the market value of investments when expressed in their local currencies and an increase in value that arises from changes in exchange rates (increasing the reported value of investments when expressed in US dollars). Movements in the value of plan assets during the year are shown in detail in the table on page 162.

		2009		2008		2007
	Expected long-term rate of return	**Market value**	Expected long-term rate of return	Market value	Expected long-term rate of return	Market value
	%	**$ million**	%	$ million	%	$ million
UK pension plans						
Equities	**8.0**	**16,945**	8.0	13,704	8.0	24,106
Bonds	**5.3**	**3,701**	6.1	3,258	4.4	5,279
Property	**6.5**	**1,269**	6.5	978	6.5	1,259
Cash	**1.1**	**634**	2.9	299	5.6	977
	7.3	**22,549**	7.4	18,239	7.3	31,621
US pension plans						
Equities	**8.5**	**4,326**	8.5	3,991	8.5	6,610
Bonds	**4.8**	**1,218**	3.7	1,247	5.0	1,347
Property	**8.0**	**8**	8.0	8	8.0	16
Cash	**0.9**	**271**	1.9	131	3.6	72
	8.0	**5,823**	8.0	5,377	8.0	8,045
US other post-retirement benefit plans						
Equities	**8.5**	**8**	8.5	9	8.5	17
Bonds	**4.8**	**4**	3.7	4	5.0	6
	7.6	**12**	7.3	13	7.6	23
Other plans						
Equities	**8.6**	**1,091**	8.4	799	8.1	1,260
Bonds	**4.4**	**1,651**	4.2	1,481	5.0	1,491

Property	**6.5**	**82**	6.3	127	5.7	145
Cash	**2.0**	**245**	3.1	118	4.2	214
	5.9	**3,069**	5.8	2,525	6.4	3,110

The assumed rate of investment return, discount rate, inflation, US healthcare cost trend rate and the mortality assumptions all have a significant effect on the amounts reported.

A one-percentage point change in the following assumptions for the group s plans would have had the effects shown in the table below. The effects shown for the expense in 2010 include current service cost and interest on plan liabilities.

		$ million
	One-percentage point	
	Increase	**Decrease**
Investment return		
Effect on pension and other post-retirement benefit expense in 2010	**(313)**	**313**
Discount rate		
Effect on pension and other post-retirement benefit expense in 2010	**(75)**	**98**
Effect on pension and other post-retirement benefit obligation at 31 December 2009	**(4,778)**	**6,084**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2010	**424**	**(343)**
Effect on pension and other post-retirement benefit obligation at 31 December 2009	**4,394**	**(3,706)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2010	**31**	**(28)**
Effect on US other post-retirement obligation at 31 December 2009	**339**	**(304)**

One additional year of longevity in the mortality assumptions would have the effects shown in the table below. The effect shown for the expense in 2010 includes current service cost and interest on plan liabilities.

				$ million
	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**German pension plans**
One additional year s longevity				
Effect on pension and other post-retirement benefit expense in 2010	**39**	**5**	**4**	**9**
Effect on pension and other post-retirement benefit obligation at 31 December 2009	**528**	**90**	**62**	**149**

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Notes on financial statements

35. Pensions and other post-retirement benefits continued

					$ million
					2009
	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	**311**	**243**	**48**	**117**	**719**
Past service cost			**(22)**	**1**	**(21)**
Settlement, curtailment and special termination benefits	**37**			**53**	**90**
Payments to defined contribution plans		**205**		**28**	**233**
Total operating charge[b]	**348**	**448**	**26**	**199**	**1,021**
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	**1,426**	**405**	**1**	**147**	**1,979**
Interest on plan liabilities	**(1,112)**	**(456)**	**(183)**	**(420)**	**(2,171)**
Other finance income (expense)	**314**	**(51)**	**(182)**	**(273)**	**(192)**
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	**1,761**	**617**	**2**	**169**	**2,549**
Change in assumptions underlying the present value of the plan liabilities	**(2,217)**	**(501)**	**(50)**	**(42)**	**(2,810)**
Experience gains and losses arising on the plan liabilities	**(141)**	**(229)**	**71**	**(122)**	**(421)**
Actuarial (loss) gain recognized in other comprehensive income	**(597)**	**(113)**	**23**	**5**	**(682)**
Movements in benefit obligation during the year					
Benefit obligation at 1 January	**16,655**	**7,534**	**3,003**	**7,655**	**34,847**
Exchange adjustments	**1,896**			**363**	**2,259**
Current service cost[a]	**311**	**243**	**48**	**117**	**719**

Past service cost			**(22)**	**1**	**(21)**
Interest cost	**1,112**	**456**	**183**	**420**	**2,171**
Curtailment				**11**	**11**
Settlement				**(3)**	**(3)**
Special termination benefits[c]	**37**			**45**	**82**
Contributions by plan participants	**37**			**10**	**47**
Benefit payments (funded plans)[d]	**(977)**	**(1,371)**	**(4)**	**(209)**	**(2,561)**
Benefit payments (unfunded plans)[d]	**(4)**	**(73)**	**(191)**	**(399)**	**(667)**
Disposals				**(42)**	**(42)**
Actuarial (gain) loss on obligation	**2,358**	**730**	**(21)**	**164**	**3,231**
Benefit obligation at 31 December[a,e]	**21,425**	**7,519**	**2,996**	**8,133**	**40,073**
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	**18,239**	**5,377**	**13**	**2,525**	**26,154**
Exchange adjustments	**2,054**			**242**	**2,296**
Expected return on plan assets[a,f]	**1,426**	**405**	**1**	**147**	**1,979**
Contributions by plan participants	**37**			**10**	**47**
Contributions by employers (funded plans)	**9**	**795**		**204**	**1,008**
Benefit payments (funded plans)[d]	**(977)**	**(1,371)**	**(4)**	**(209)**	**(2,561)**
Disposals				**(19)**	**(19)**
Actuarial gain on plan assets[f]	**1,761**	**617**	**2**	**169**	**2,549**
Fair value of plan assets at 31 December	**22,549**	**5,823**	**12**	**3,069**	**31,453**
Surplus (deficit) at 31 December	**1,124**	**(1,696)**	**(2,984)**	**(5,064)**	**(8,620)**
Represented by					
Asset recognized	**1,290**			**100**	**1,390**
Liability recognized	**(166)**	**(1,696)**	**(2,984)**	**(5,164)**	**(10,010)**
	1,124	**(1,696)**	**(2,984)**	**(5,064)**	**(8,620)**
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	**1,287**	**(1,280)**	**(33)**	**(164)**	**(190)**
Unfunded	**(163)**	**(416)**	**(2,951)**	**(4,900)**	**(8,430)**
	1,124	**(1,696)**	**(2,984)**	**(5,064)**	**(8,620)**
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	**(21,262)**	**(7,103)**	**(45)**	**(3,233)**	**(31,643)**
Unfunded	**(163)**	**(416)**	**(2,951)**	**(4,900)**	**(8,430)**
	(21,425)	**(7,519)**	**(2,996)**	**(8,133)**	**(40,073)**

[a] The costs of managing the plan s investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.

[b] Included within production and manufacturing expenses and distribution and administration expenses.

[c] The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.

[d] The benefit payments amount shown above comprises $3,174 million benefits plus $54 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for other plans includes $3,880 million for the German plan, which is largely unfunded.

[f] The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial gain on plan assets as disclosed above.

At 31 December 2009, reimbursement balances due from or to other companies in respect of pensions amounted to $443 million reimbursement assets (2008 $455 million) and $14 million reimbursement liabilities (2008 $61 million). These balances are not included as part of the pension liability, but are reflected elsewhere in the group balance sheet.

Notes on financial statements

35. Pensions and other post-retirement benefits continued

					$ million 2008
	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	448	235	40	128	851
Past service cost	7	74		1	82
Settlement, curtailment and special termination benefits	30			12	42
Payments to defined contribution plans		170		25	195
Total operating charge[b]	485	479	40	166	1,170
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	2,094	632	2	194	2,922
Interest on plan liabilities	(1,239)	(444)	(198)	(450)	(2,331)
Other finance income (expense)	855	188	(196)	(256)	591
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	(6,946)	(2,895)	(8)	(404)	(10,253)
Change in assumptions underlying the present value of the plan liabilities	1,570	3	215	214	2,002
Experience gains and losses arising on the plan liabilities	(73)	(194)	18	70	(179)
Actuarial (loss) gain recognized in other comprehensive income	(5,449)	(3,086)	225	(120)	(8,430)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	23,927	7,409	3,178	8,586	43,100
Exchange adjustments	(6,408)			(628)	(7,036)
Current service cost[a]	448	235	40	128	851

Past service cost	7	74		1	82
Interest cost	1,239	444	198	450	2,331
Curtailment				(3)	(3)
Settlement	(3)			(3)	(6)
Special termination benefits[c]	33			18	51
Contributions by plan participants	42			12	54
Benefit payments (funded plans)[d]	(1,131)	(767)	(4)	(203)	(2,105)
Benefit payments (unfunded plans)[d]	(2)	(52)	(176)	(419)	(649)
Actuarial (gain) loss on obligation	(1,497)	191	(233)	(284)	(1,823)
Benefit obligation at 31 December[a e]	16,655	7,534	3,003	7,655	34,847
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	31,621	8,045	23	3,110	42,799
Exchange adjustments	(7,447)			(314)	(7,761)
Expected return on plan assets[a f]	2,094	632	2	194	2,922
Contributions by plan participants	42			12	54
Contributions by employers (funded plans)	6	362		130	498
Benefit payments (funded plans)[d]	(1,131)	(767)	(4)	(203)	(2,105)
Actuarial loss on plan assets[f]	(6,946)	(2,895)	(8)	(404)	(10,253)
Fair value of plan assets at 31 December	18,239	5,377	13	2,525	26,154
Surplus (deficit) at 31 December	1,584	(2,157)	(2,990)	(5,130)	(8,693)
Represented by					
Asset recognized	1,682			56	1,738
Liability recognized	(98)	(2,157)	(2,990)	(5,186)	(10,431)
	1,584	(2,157)	(2,990)	(5,130)	(8,693)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	1,682	(1,734)	(31)	(354)	(437)
Unfunded	(98)	(423)	(2,959)	(4,776)	(8,256)
	1,584	(2,157)	(2,990)	(5,130)	(8,693)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(16,557)	(7,111)	(44)	(2,879)	(26,591)
Unfunded	(98)	(423)	(2,959)	(4,776)	(8,256)
	(16,655)	(7,534)	(3,003)	(7,655)	(34,847)

[a] The costs of managing the plan s investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.

[b] Included within production and manufacturing expenses and distribution and administration expenses.

[c] The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.

[d] The benefit payments amount shown above comprises $2,697 million benefits plus $57 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for other plans includes $3,837 million for the German plan, which is largely unfunded.

[f] The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial loss on plan assets as disclosed above.

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35. Pensions and other post-retirement benefits continued

					$ million 2007
	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	492	227	43	132	894
Past service cost	5	10			15
Settlement, curtailment and special termination benefits	36			2	38
Payments to defined contribution plans		184		25	209
Total operating charge[b]	533	421	43	159	1,156
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	2,075	613	2	165	2,855
Interest on plan liabilities	(1,198)	(425)	(190)	(390)	(2,203)
Other finance income (expense)	877	188	(188)	(225)	652
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	406	(28)		(76)	302
Change in assumptions underlying the present value of the plan liabilities	513	358	137	607	1,615
Experience gains and losses arising on the plan liabilities	(162)	(27)	29	(40)	(200)
Actuarial gain recognized in other comprehensive income	757	303	166	491	1,717

[a] The costs of managing the plan s investments are treated as being part of the investment return, the costs of administering our pension plan benefits are generally included in current service cost, and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.

[b] Included within production and manufacturing expenses and distribution and administration expenses.

					$ million
	2009	2008	2007	2006	2005
History of surplus (deficit) and of experience gains and losses					
Benefit obligation at 31 December	**40,073**	34,847	43,100	42,433	38,855
Fair value of plan assets at 31 December	**31,453**	26,154	42,799	39,910	32,907
Deficit	**(8,620)**	(8,693)	(301)	(2,523)	(5,948)
Experience losses on plan liabilities	**(421)**	(178)	(200)	(124)	(212)
Actual return less expected return on pension plan assets	**2,549**	(10,253)	302	1,967	3,364
Actual return on plan assets	**4,528**	(7,331)	3,157	4,377	5,502
Actuarial (loss) gain recognized in other comprehensive income	**(682)**	(8,430)	1,717	2,615	975
Cumulative amount recognized in other comprehensive income	**(3,622)**	(2,940)	5,490	3,773	1,158

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2019 are as follows:

					$ million
	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
2010	**1,003**	**618**	**201**	**612**	**2,434**
2011	**1,019**	**637**	**206**	**587**	**2,449**
2012	**1,061**	**679**	**208**	**581**	**2,529**
2013	**1,095**	**677**	**213**	**578**	**2,563**
2014	**1,148**	**672**	**218**	**584**	**2,622**
2015-2019	**6,496**	**3,275**	**1,123**	**2,835**	**13,729**

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36. Called-up share capital

The allotted, called-up and fully paid share capital at 31 December was as follows:

		2009		2008		2007
Issued	**Shares (thousand)**	**$ million**	Shares (thousand)	$ million	Shares (thousand)	$ million
8% cumulative first preference shares of £1 each	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,618,458**	**5,155**	20,863,424	5,216	21,457,301	5,364
Issue of new shares for employee share schemes[a]	**11,207**	**3**	24,791	6	69,273	18
Repurchase of ordinary share capital[b]			(269,757)	(67)	(663,150)	(166)
At 31 December	**20,629,665**	**5,158**	20,618,458	5,155	20,863,424	5,216
		5,179		5,176		5,237
Authorized						
8% cumulative first preference shares of £1 each	**7,250**	**12**	7,250	12	7,250	12
9% cumulative second preference shares of £1 each	**5,500**	**9**	5,500	9	5,500	9
Ordinary shares of 25 cents each	**36,000,000**	**9,000**	36,000,000	9,000	36,000,000	9,000

[a] Consideration received relating to the issue of new shares for employee share schemes amounted to $84 million (2008 $180 million and 2007 $492 million).

[b] Purchased for a total consideration of nil (2008 $2,914 million and 2007 $7,497 million), all of which were for cancellation. At 31 December 2009, 112,803,287 (2008 150,444,408 and 2007 150,966,096) ordinary shares bought back were awaiting cancellation. These shares have been excluded from ordinary shares in issue shown above. Transaction costs of share repurchases amounted to nil (2008 $16 million and 2007 $40 million).

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

Treasury shares

		2009		2008		2007
	Shares (thousand)	**Nominal value $ million**	Shares (thousand)	Nominal value $ million	Shares (thousand)	Nominal value $ million
At 1 January	**1,888,151**	**472**	1,940,639	485	1,946,805	487
Shares gifted to the Employee Share Ownership Plans	**(1,265)**	**(1)**	(10,000)	(2)	(1,700)	
Shares transferred at market price to the Employee Share Ownership Plans			(20,000)	(5)		
Shares re-issued to employee share schemes	**(17,109)**	**(4)**	(22,488)	(6)	(4,466)	(2)
At 31 December	**1,869,777**	**467**	1,888,151	472	1,940,639	485

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 9.2% (2008 9.3% and 2007 9.1%) of the called-up ordinary share capital of the company.

During 2009, the movement in treasury shares represented less than 0.1% (2008 0.25% and 2007 less than 0.1%) of the ordinary share capital of the company.

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37. Capital and reserves

	Share capital	**Share premium account**	**Capital redemption reserve**
At 1 January 2009	**5,176**	**9,763**	**1,072**
Currency translation differences (including recycling)			
Actuarial gain relating to pensions and other post-retirement benefits			
Available-for-sale investments (including recycling)			
Cash flow hedges (including recycling)			
Profit for the year			
Total comprehensive income			
Dividends			
Share-based payments[a]	**3**	**84**	
Changes in associates equity			
Minority interest buyout			
At 31 December 2009	**5,179**	**9,847**	**1,072**

	Share capital	Share premium account	Capital redemption reserve
At 1 January 2008	5,237	9,581	1,005
Currency translation differences (including recycling)			
Actuarial gain relating to pensions and other post-retirement benefits			
Available-for-sale investments (including recycling)			
Cash flow hedges (including recycling)			
Profit for the year			
Total comprehensive income			
Dividends			
Repurchase of ordinary share capital	(67)		67
Share-based payments[a]	6	182	
Minority interest buyout			
At 31 December 2008	5,176	9,763	1,072

	Share capital	Share premium account	Capital redemption reserve
At 1 January 2007	5,385	9,074	839
Currency translation differences (including recycling)			
Actuarial gain relating to pensions and other post-retirement benefits			
Available-for-sale investments (including recycling)			
Cash flow hedges (including recycling)			
Profit for the year			
Total comprehensive income			
Dividends			
Repurchase of ordinary share capital	(166)		166
Share-based payments[a]	18	507	
At 31 December 2007	5,237	9,581	1,005

[a] Includes new share issues and movements in own shares and treasury shares where these relate to share-based payment plans.

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$ million

Merger reserve	**Other reserve**	**Own shares**	**Treasury shares**	**Foreign currency translation reserve**	**Available-for-sale investments**	**Cash flow hedges**	**Share-based payment reserve**	**Profit and loss account**	**BP shareholders equity**	**Minority interest**	**Total equity**
27,206		**(326)**	**(21,513)**	**2,353**	**63**	**(866)**	**1,295**	**67,080**	**91,303**	**806**	**92,109**
				2,458	**(2)**	**(37)**			**2,419**	**(56)**	**2,363**
								(478)	**(478)**		**(478)**
					693				**693**		**693**
						925			**925**		**925**
								16,578	**16,578**	**181**	**16,759**
				2,458	**691**	**888**		**16,100**	**20,137**	**125**	**20,262**
								(10,483)	**(10,483)**	**(416)**	**(10,899)**
		112	**210**				**289**	**23**	**721**		**721**
								(43)	**(43)**		**(43)**
								(22)	**(22)**	**(15)**	**(37)**
27,206		**(214)**	**(21,303)**	**4,811**	**754**	**22**	**1,584**	**72,655**	**101,613**	**500**	**102,113**

Merger reserve	Other reserve	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders equity	Minority interest	Total equity
27,206		(60)	(22,112)	6,540	481	106	1,196	64,510	93,690	962	94,652
				(4,187)					(4,187)	(75)	(4,262)
								(5,828)	(5,828)		(5,828)
					(418)				(418)		(418)
						(972)			(972)		(972)
								21,157	21,157	509	21,666
				(4,187)	(418)	(972)		15,329	9,752	434	10,186
								(10,342)	(10,342)	(425)	(10,767)
								(2,414)	(2,414)		(2,414)
		(266)	599				99	(3)	617		617
										(165)	(165)

27,206		(326)	(21,513)	2,353	63	(866)	1,295	67,080	91,303	806	92,109

Merger reserve	Other reserve	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders equity	Minority interest	Total equity
27,201	5	(154)	(22,182)	4,685	386	39	859	58,487	84,624	841	85,465
				1,855					1,855	24	1,879
								1,290	1,290		1,290
					95				95		95
						67			67		67
								20,845	20,845	324	21,169
				1,855	95	67		22,135	24,152	348	24,500
								(8,106)	(8,106)	(227)	(8,333)
								(7,997)	(7,997)		(7,997)
5	(5)	94	70				337	(9)	1,017		1,017
27,206		(60)	(22,112)	6,540	481	106	1,196	64,510	93,690	962	94,652

Notes on financial statements

37. Capital and reserves continued

Share capital

The balance on the share capital account represents the aggregate nominal value of all ordinary and preference shares in issue, including treasury shares.

Share premium account

The balance on the share premium account represents the amounts received in excess of the nominal value of the ordinary and preference shares.

Capital redemption reserve

The balance on the capital redemption reserve represents the aggregate nominal value of all the ordinary shares repurchased and cancelled.

Merger reserve

The balance on the merger reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares.

Other reserve

The balance on the other reserve represented the fair value of the consideration given in excess of the nominal value of the ordinary shares issued in the ARCO acquisition on the exercise of ARCO share options.

Own shares

Own shares represent BP shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans.

Treasury shares

Treasury shares represent BP shares repurchased and available for re-issue.

Foreign currency translation reserve

The foreign currency translation reserve is used to record exchange differences arising from the translation of the financial statements of foreign operations. Upon disposal of foreign operations, the related accumulated exchange differences are recycled to the income statement. This reserve is also used to record the effect of hedging net investments in foreign operations.

Available-for-sale investments

This reserve records the changes in fair value of available-for-sale investments. On disposal or impairment, the cumulative changes in fair value are recycled to the income statement.

Cash flow hedges

This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. When the hedged transaction occurs, the gain or loss on the hedging instrument is transferred out of equity to either profit or loss or the carrying value of assets, as appropriate. If the forecast transaction is no longer expected to occur the gain or loss recognized in equity is transferred to profit or loss.

Share-based payment reserve

This reserve represents cumulative amounts charged to profit in respect of employee share-based payment plans where the scheme has not yet been settled by means of an award of shares to an individual.

Profit and loss account

The balance held on this reserve is the accumulated retained profits of the group.

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37. Capital and reserves continued
The pre-tax amounts of each component of other comprehensive income, and the related amounts of tax, are shown in the table below.

			$ million
			2009
	Pre-tax	**Tax**	**Net of tax**
Currency translation differences (including recycling)	**1,799**	**564**	**2,363**
Actuarial loss relating to pensions and other post-retirement benefits	**(682)**	**204**	**(478)**
Available-for-sale investments (including recycling)	**707**	**(14)**	**693**
Cash flow hedges (including recycling)	**1,154**	**(229)**	**925**
Other comprehensive income	**2,978**	**525**	**3,503**

			$million
			2008
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	(4,362)	100	(4,262)
Actuarial loss relating to pensions and other post-retirement benefits	(8,430)	2,602	(5,828)
Available-for-sale investments (including recycling)	(468)	50	(418)
Cash flow hedges (including recycling)	(1,166)	194	(972)
Other comprehensive income	(14,426)	2,946	(11,480)

			$million
			2007
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	1,740	139	1,879
Actuarial gain relating to pensions and other post-retirement benefits	1,717	(427)	1,290
Available-for-sale investments (including recycling)	109	(14)	95
Cash flow hedges (including recycling)	41	26	67
Other comprehensive income	3,607	(276)	3,331

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Notes on financial statements

38. Share-based payments

Effect of share-based payment transactions on the group s result and financial position

			$ million
	2009	2008	2007
Total expense recognized for equity-settled share-based payment transactions	**506**	524	412
Total expense (credit) recognized for cash-settled share-based payment transactions	**15**	(16)	16
Total expense recognized for share-based payment transactions	**521**	508	428
Closing balance of liability for cash-settled share-based payment transactions	**32**	21	40
Total intrinsic value for vested cash-settled share-based payments	**7**	2	22

For ease of presentation, option and share holdings detailed in the tables within this note are stated as UK ordinary share equivalents in US dollars. US employees are granted American Depositary Shares (ADSs) or options over the company s ADSs (one ADS is equivalent to six ordinary shares). The share-based payment plans that existed during the year are detailed below. All plans are ongoing unless otherwise stated.

Plans for executive directors

Executive Directors Incentive Plan (EDIP) share element

An equity-settled incentive plan for executive directors with a three-year performance period. For share plan performance periods 2007-2009 and 2008-2010 the award of shares is determined by comparing BP s total shareholder return (TSR) against the other oil majors (ExxonMobil, Shell, Total and Chevron). For the performance period 2009-2011 the award of shares is determined 50% on TSR versus a competitor group of oil majors (which in this period also included ConocoPhillips) and 50% on a balanced scorecard (BSC) of three underlying performance measures versus the same competitor group. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. The directors remuneration report on pages 77 to 88 includes full details of the plan.

Executive Directors Incentive Plan (EDIP) share option element

An equity-settled share option plan for executive directors that permits options to be granted at an exercise price no lower than the market price of a share on the date that the option is granted. The options are exercisable up to the seventh anniversary of the grant date and the last grants were made in 2004. From 2005 onwards the remuneration committee s policy is not to make further grants of share options to executive directors.

Plans for senior employees

The group operates a number of equity-settled share plans under which share units are granted to its senior leaders and certain employees. These plans typically have a three-year performance or restricted period during which the units accrue net notional dividends which are treated as having been reinvested. Leaving employment during the three-year period will normally preclude the conversion of units into shares, but special arrangements apply where the participant leaves for a qualifying reason.

Grants are settled in cash where participants are located in a country whose regulatory environment prohibits the holding of BP shares.

Performance unit plans

The number of units granted is made by reference to level of seniority of the employees. The number of units converted to shares is determined by reference to performance measures over the three-year performance period. The main performance measure used is BP s TSR compared against the other oil majors. In addition, free cash flow (FCF) is used as a performance measure for one of the performance plans. Plans included in this category are the Competitive Performance Plan (CPP), the Medium Term Performance Plan (MTPP) and, in part, the Performance Share Plan (PSP).

Restricted share unit plans

Share unit grants under BP s restricted plans typically take into account the employee s performance in either the current or the prior year, track record of delivery, business and leadership skills and long-term potential. One restricted share unit plan used in special circumstances for senior employees, such as recruitment and retention, normally has no performance conditions. Plans included in this category are the Executive Performance Plan (EPP), the Restricted Share Plan (RSP), the Deferred Annual Bonus Plan (DAB) and, in part, the Performance Share Plan (PSP).

BP Share Option Plan (BPSOP)

Share options with an exercise price equivalent to the market price of a share immediately preceding the date of grant were granted to participants annually until 2006. There were no performance conditions and the options are exercisable between the third and tenth anniversaries of the grant date.

Savings and matching plans

BP ShareSave Plan

This is a savings-related share option plan under which employees save on a monthly basis, over a three- or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and options are granted annually, usually in June. Participants leaving for a qualifying reason have six months in which to use their savings to exercise their options on a pro-rated basis.

Notes on financial statements

38. Share-based payments continued
BP ShareMatch Plans
These are matching share plans under which BP matches employees own contributions of shares up to a predetermined limit. The plans are run in the UK and in more than 70 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. In other countries the plan is run on an annual basis with shares being held in trust for three years. The plan is operated on a cash basis in those countries where there are regulatory restrictions preventing the holding of BP shares. When the employee leaves BP all shares must be removed from trust and units under the plan operated on a cash basis must be encashed.
Local plans
In some countries BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances.

Employee Share Ownership Plans (ESOPs)

ESOPs have been established to acquire BP shares to satisfy any awards made to participants under the BP share plans as required. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the group. Until such time as the company s own shares held by the ESOP trusts vest unconditionally to employees, the amount paid for those shares is deducted in arriving at shareholders equity (see Note 37). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2009 the ESOPs held 18,062,246 shares (2008 29,051,082 shares and 2007 6,448,838 shares) for potential future awards, which had a market value of $174 million (2008 $220 million and 2007 $79 million).

Share option transactions		**2009**		2008		2007
	Number of options	**Weighted average exercise price $**	Number of options	Weighted average exercise price $	Number of options	Weighted average exercise price $
Outstanding at 1 January	**326,254,599**	**8.70**	358,094,243	8.51	426,471,462	8.25
Granted	**9,679,836**	**6.55**	8,062,899	8.96	6,004,025	9.11
Forfeited	**(5,954,325)**	**8.81**	(2,502,784)	8.50	(3,924,714)	9.10
Exercised	**(21,293,871)**	**7.53**	(37,277,895)	6.97	(69,715,558)	6.94
Expired	**(12,790,882)**	**8.01**	(121,864)	7.00	(740,972)	8.68
Outstanding at 31 December	**295,895,357**	**8.73**	326,254,599	8.70	358,094,243	8.51
Exercisable at 31 December	**274,685,068**	**8.80**	260,178,938	8.22	238,707,055	7.70

As share options are exercised continuously throughout the year, the weighted average share price during the year of $9.10 (2008 $10.87 and 2007 $11.72) is representative of the weighted average share price at the date of exercise. For the options outstanding at 31 December 2009, the exercise price ranges and weighted average remaining contractual lives are shown below.

	Options outstanding			Options exercisable	
Range of exercise prices	**Number of shares**	**Weighted average remaining life Years**	**Weighted average exercise price $**	**Number of shares**	**Weighted average exercise price $**
$6.18 $7.61	**53,511,852**	**3.31**	**6.43**	**43,956,777**	**6.40**
$7.62 $9.05	**143,736,259**	**2.48**	**8.18**	**137,625,273**	**8.16**
$9.06 $10.48	**27,046,156**	**4.10**	**9.83**	**21,501,928**	**10.01**
$10.49 $11.92	**71,601,090**	**5.81**	**11.14**	**71,601,090**	**11.14**
	295,895,357	**3.58**	**8.73**	**274,685,068**	**8.80**

Fair values and associated details for options and shares granted

		2009		2008		2007
	ShareSave 3 year	**ShareSave 5 year**	ShareSave 3 year	ShareSave 5 year	ShareSave 3 year	ShareSave 5 year
Option pricing model used	**Binomial**	**Binomial**	Binomial	Binomial	Binomial	Binomial
Weighted average fair value	**$1.07**	**$1.07**	$1.82	$1.74	$3.57	$3.79
Weighted average share price	**$7.87**	**$7.87**	$11.26	$11.26	$12.10	$12.10
Weighted average exercise price	**$6.92**	**$6.92**	$9.70	$9.70	$9.13	$9.13
Expected volatility	**32%**	**32%**	23%	23%	21%	21%
Option life	**3.5 years**	**5.5 years**	3.5 years	5.5 years	3.5 years	5.5 years
Expected dividends	**7.40%**	**7.40%**	4.60%	4.60%	3.48%	3.48%
Risk free interest rate	**3.00%**	**3.75%**	5.00%	5.00%	5.75%	5.75%
Expected exercise behaviour	**100% year 4**	**100% year 6**	100% year 4	100% year 6	100% year 4	100% year 6

The group uses a valuation model to determine the fair value of options granted. The model uses the implied volatility of ordinary share price for the quarter within which the grant date of the relevant plan falls. The fair value is adjusted for the expected rates of early cancellation. Management is responsible for all inputs and assumptions in relation to the model, including the determination of expected volatility.

Notes on financial statements

38. Share-based payments continued

Shares granted in 2009	**CPP**	**EPP**	**EDIP-TSR**	**EDIP-BSC**	**RSP**	**DAB**	**PSP**
Number of equity instruments granted (million)	**1.4**	**7.6**	**2.1**	**2.1**	**2.4**	**38.9**	**16.5**
Weighted average fair value	**$9.76**	**$6.56**	**$2.74**	**$7.27**	**$8.76**	**$6.56**	**$8.32**
Fair value measurement basis	**Monte Carlo**	**Market value**	**Monte Carlo**	**Market value**	**Market value**	**Market value**	**Monte Carlo**

Shares granted in 2008	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-RET[a]	RSP	DAB	PSP
Number of equity instruments granted (million)	9.1	9.1	2.6	0.5	7.7	5.8	16.7
Weighted average fair value	$5.07	$10.34	$4.55	$11.13	$8.83	$10.34	$12.89
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value	Monte Carlo

Shares granted in 2007	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-LTL[b]	RSP	DAB	PSP
Number of equity instruments granted (million)	9.4	8.5	4.5	0.5	7.7	4.4	14.8
Weighted average fair value	$4.73	$10.02	$2.81	$9.92	$11.93	$10.02	$12.37
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value	Monte Carlo

[a] EDIP retention element.
[b] EDIP long-term leadership element.

The group used a Monte Carlo simulation to determine the fair value of the TSR element of the 2009, 2008 and 2007 CPP, PSP, MTPP and EDIP plans. In accordance with the rules of the plans the model simulates BP s TSR and compares it against our principal strategic competitors over the three-year period of the plans. The model takes into account the historic dividends, share price volatilities and covariances of BP and each comparator company to produce a predicted distribution of relative share performance. This is applied to the reward criteria to give an expected value of the TSR element.

Accounting expense does not necessarily represent the actual value of share-based payments made to recipients, which are determined by the remuneration committee according to established criteria.

39. Employee costs and numbers

Employee costs	2009	2008	$ million 2007
Wages and salaries[a]	**9,702**	10,388	9,808
Social security costs	**780**	805	771
Share-based payments	**521**	508	428
Pension and other post-retirement benefit costs	**1,213**	579	504
	12,216	12,280	11,511

Number of employees at 31 December	2009	2008	2007
Exploration and Production	**21,500**	21,400	21,800
Refining and Marketing[b]	**51,600**	61,500	67,200
Other businesses and corporate	**7,200**	9,100	9,100
	80,300	92,000	98,100
By geographical area			
US	**22,800**	29,300	33,000
Non-US[b]	**57,500**	62,700	65,100
	80,300	92,000	98,100

			2009			2008			2007
Average number of employees	**US**	**Non-US**	**Total**	US	Non-US	Total	US	Non-US	Total
Exploration and Production	**7,900**	**13,800**	**21,700**	7,800	13,800	21,600	7,700	13,800	21,500
Refining and Marketing	**14,700**	**40,700**	**55,400**	21,600	43,400	65,000	23,400	43,900	67,300
Other businesses and corporate	**2,300**	**5,800**	**8,100**	2,600	6,500	9,100	2,500	5,900	8,400
	24,900	**60,300**	**85,200**	32,000	63,700	95,700	33,600	63,600	97,200

[a] Includes termination payments of $945 million (2008 $669 million and 2007 $422 million).

[b] Includes 13,900 (2008 21,200 and 2007 24,500) service station staff.

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40. Remuneration of directors and senior management

Remuneration of directors

			$ million
	2009	2008	2007
Total for all directors			
Emoluments	**19**	19	26
Gains made on the exercise of share options	**2**	1	2
Amounts awarded under incentive schemes	**2**		10

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus bonuses awarded for the year. Ex gratia superannuation payments of $3 million were included in 2007. Also included was compensation for loss of office of $1 million in 2008 and $1 million in 2007.

Pension contributions

Three executive directors participated in a non-contributory pension scheme established for UK employees by a separate trust fund to which contributions are made by BP based on actuarial advice. Two US executive directors participated in the US BP Retirement Accumulation Plan during 2009.

Office facilities for former chairmen and deputy chairmen

It is customary for the company to make available to former chairmen and deputy chairmen, who were previously employed executives, the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Further information

Full details of individual directors   remuneration are given in the directors   remuneration report on pages 77 to 88.

Remuneration of directors and senior management

			$ million
	2009	2008	2007
Total for all senior management			
Short-term employee benefits	**36**	34	35
Post-retirement benefits	**3**	4	6
Share-based payments	**20**	20	22

Senior management, in addition to executive and non-executive directors, includes other senior managers who are members of the executive management team.

Short-term employee benefits

In addition to fees paid to the non-executive chairman and non-executive directors, these amounts comprise, for executive directors and senior managers, salary and benefits earned during the year, plus cash bonuses awarded for the year. Deferred annual bonus awards, to be settled in shares, are included in share-based payments. Short-term employee benefits includes an ex gratia superannuation payment of nil (2008 nil and 2007 $3 million) and compensation for loss of office of $6 million (2008 $3 million and 2007 $1 million).

Post-retirement benefits

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

Share-based payments

This is the cost to the group of senior management s participation in share-based payment plans, as measured by the fair value of options and shares granted accounted for in accordance with IFRS 2   Share-based Payments . The main plans in which senior management have participated are the EDIP and MTPP. For details of these plans refer to Note 38.

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41. Contingent liabilities

There were contingent liabilities at 31 December 2009 in respect of guarantees and indemnities entered into as part of the ordinary course of the group s business. No material losses are likely to arise from such contingent liabilities. Further information is included in Note 24.

Lawsuits arising out of the Exxon Valdez oil spill in Prince William Sound, Alaska, in March 1989 were filed against Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP s combination with Atlantic Richfield Company (Atlantic Richfield). Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages that Exxon has incurred. BP will defend any such claims vigorously. It is not possible to estimate any financial effect.

In the normal course of the group s business, legal proceedings are pending or may be brought against BP group entities arising out of current and past operations, including matters related to commercial disputes, product liability, antitrust, premises-liability claims, general environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. BP believes that the impact of these legal proceedings on the group s results of operations, liquidity or financial position will not be material.

With respect to lead pigment in paint in particular, Atlantic Richfield, a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property. Although it is not possible to predict the outcome of the legal proceedings, Atlantic Richfield believes it has valid defences that render the incurrence of a liability remote; however, the amounts claimed and the costs of implementing the remedies sought in the various cases could be substantial. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. Atlantic Richfield intends to defend such actions vigorously.

The group files income tax returns in many jurisdictions throughout the world. Various tax authorities are currently examining the group s income tax returns. Tax returns contain matters that could be subject to differing interpretations of applicable tax laws and regulations and the resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete. While it is difficult to predict the ultimate outcome in some cases, the group does not anticipate that there will be any material impact upon the group s results of operations, financial position or liquidity.

The group is subject to numerous national and local environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the group to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the group or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, service stations, terminals and waste disposal sites. In addition, the group may have obligations relating to prior asset sales or closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the group s accounting policies. While the amounts of future costs could be significant and could be material to the group s results of operations in the period in which they are recognized, it is not practical to estimate the amounts involved. BP does not expect these costs to have a material effect on the group s financial position or liquidity.

The group also has obligations to decommission oil and natural gas production facilities and related pipelines. Provision is made for the estimated costs of these activities, however there is uncertainty regarding both the amount and timing of these costs, given the long-term nature of these obligations. BP believes that the impact of any reasonably foreseeable changes to these provisions on the group s results of operations, financial position or liquidity will not be material.

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

42. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been placed at 31 December 2009 amounted to $9,812 million (2008 $14,062 million). In addition, at 31 December 2009, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $622 million (2008 $644 million) and investments in associates of $170 million (2008 $160 million).

BP s share of capital commitments of jointly controlled entities amounted to $926 million (2008 $1,540 million).

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43. Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2009 and the group percentage of ordinary share capital or joint venture interest (to nearest whole number) are set out below. The principal country of operation is generally indicated by the company s country of incorporation or by its name. Those held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of investments in subsidiaries, jointly controlled entities and associates will be attached to the parent company s annual return made to the Registrar of Companies.

Subsidiaries	%	Country of incorporation	Principal activities
International			
*BP Corporate Holdings	100	England	Investment holding
BP Exploration Op. Co.	100	England	Exploration and production
*BP Global Investments	100	England	Investment holding
*BP International	100	England	Integrated oil operations
BP Oil International	100	England	Integrated oil operations
*BP Shipping	100	England	Shipping
*Burmah Castrol	100	Scotland	Lubricants
Jupiter Insurance	100	Guernsey	Insurance
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
BP Exploration (El Djazair)	100	Bahamas	Exploration and production
Angola			
BP Exploration (Angola)	100	England	Exploration and production
Australia			
BP Oil Australia	100	Australia	Integrated oil operations
BP Australia Capital			

Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
Azerbaijan			
Amoco Caspian Sea Petroleum	100	British Virgin Islands	Exploration and production
BP Exploration (Caspian Sea)	100	England	Exploration and production
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Co.	100	US	Exploration and production
Germany			
Deutsche BP	100	Germany	Refining and marketing and petrochemicals
Indonesia			
BP Berau	100	US	Exploration and production

Subsidiaries	%	Country of incorporation	Principal activities
Netherlands			
BP Capital	100	Netherlands	Finance
BP Nederland	100	Netherlands	Refining and marketing
New Zealand			
BP Oil New Zealand	100		Marketing

		New Zealand	
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
South Africa			
*BP Southern Africa	75	South Africa	Refining and marketing
Trinidad & Tobago			
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England	Finance
BP Oil UK	100	England	Marketing
Britoil	100	Scotland	Exploration and production
US			
*BP Holdings North America	100	England	Investment holding
Atlantic Richfield Co. BP America BP America Production Company BP Amoco Chemical Company BP Company North America BP Corporation North America BP Exploration (Alaska) Inc. BP Products North America BP West Coast Products Standard Oil Co.	100	US	Exploration and production, refining and marketing, pipelines and petrochemicals

BP Capital Markets America	Finance

43. Subsidiaries, jointly controlled entities and associates continued

Jointly controlled entities	%	Country of incorporation or registration	Principal activities
Angola LNG Supply Services	14	US	LNG processing and transportation
Atlantic 4 Holdings	38	US	LNG manufacture
Atlantic LNG 2/3 Company of Trinidad and Tobago	43	Trinidad & Tobago	LNG manufacture
BP-Husky Refining	50	US	Refining
Elvary Neftegaz Holdings BV	49	Netherlands	Exploration and appraisal
Pan American Energy[a]	60	US	Exploration and production
Petromonagas	17	Venezuela	Exploration and production
Ruhr Oel	50	Germany	Refining and marketing and petrochemicals
Shanghai SECCO Petrochemical Co.	50	China	Petrochemicals
Sunrise Oil Sands	50	Canada	Exploration and production
United Gas Derivatives Company	33	Egypt	LNG manufacture
Watson Cogeneration[a]	51	US	Power generation

[a]The entity is not controlled by BP as certain key business decisions require joint approval of both BP and the minority partner. It is therefore classified as a jointly controlled entity rather than a subsidiary.

Associates	%	Country of incorporation	Principal activities
Abu Dhabi			
Abu Dhabi Marine Areas	37	England	Crude oil production
Abu Dhabi Petroleum Co.	24	England	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Co.	30	Cayman Islands	Pipelines
South Caucasus Pipeline Co.	26	Cayman Islands	Pipelines
Russia			
TNK-BP	50	British Virgin Islands	Integrated oil operations
Trinidad & Tobago			
Atlantic LNG Company of Trinidad and Tobago	34	Trinidad & Tobago	LNG manufacture

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Notes on financial statements

44. Condensed consolidating information on certain US subsidiaries

BP p.l.c. fully and unconditionally guarantees the payment obligations of its 100% owned subsidiary BP Exploration (Alaska) Inc. under the BP Prudhoe Bay Royalty Trust. The following financial information for BP p.l.c., BP Exploration (Alaska) Inc. and all other subsidiaries on a condensed consolidating basis is intended to provide investors with meaningful and comparable financial information about BP p.l.c. and its subsidiary issuers of registered securities and is provided pursuant to Rule 3-10 of Regulation S-X in lieu of the separate financial statements of each subsidiary issuer of public debt securities. Investments include the investments in subsidiaries recorded under the equity method for the purposes of the condensed consolidating financial information. Equity income of subsidiaries is the group s share of profit related to such investments. The eliminations and reclassifications column includes the necessary amounts to eliminate the intercompany balances and transactions between BP p.l.c., BP Exploration (Alaska) Inc. and other subsidiaries. The financial information presented in the following tables for BP Exploration (Alaska) Inc. for all years includes equity income arising from subsidiaries of BP Exploration (Alaska) Inc. some of which operate outside of Alaska and excludes the BP group s midstream operations in Alaska that are reported through different legal entities and that are included within the other subsidiaries column in these tables. BP p.l.c. also fully and unconditionally guarantees securities issued by BP Capital Markets p.l.c. and BP Capital Markets America Inc. These companies are 100%-owned finance subsidiaries of BP p.l.c.

Income statement

					$ million
For the year ended 31 December					**2009**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Sales and other operating revenues	**4,189**		**239,272**	**(4,189)**	**239,272**
Earnings from jointly controlled entities after interest and tax			**1,286**		**1,286**
Earnings from associates after interest and tax			**2,615**		**2,615**
Equity-accounted income of subsidiaries after interest and tax	**838**	**17,315**		**(18,153)**	
Interest and other revenues	**17**	**144**	**832**	**(201)**	**792**
Gains on sale of businesses and fixed assets		**9**	**2,173**	**(9)**	**2,173**
Total revenues and other income	**5,044**	**17,468**	**246,178**	**(22,552)**	**246,138**
Purchases	**510**		**167,451**	**(4,189)**	**163,772**
Production and manufacturing expenses	**970**		**22,232**		**23,202**
Production and similar taxes	**602**		**3,150**		**3,752**
Depreciation, depletion and amortization	**424**		**11,682**		**12,106**
Impairment and losses on sale of businesses and fixed assets			**2,333**		**2,333**
Exploration expense			**1,116**		**1,116**

Distribution and administration expenses	**27**	**1,145**	**12,974**	**(108)**	**14,038**
Fair value gain on embedded derivatives			**(607)**		**(607)**
Profit before interest and taxation	**2,511**	**16,323**	**25,847**	**(18,255)**	**26,426**
Finance costs	**22**	**26**	**1,155**	**(93)**	**1,110**
Net finance (income) expense relating to pensions and other post-retirement benefits	**10**	**(310)**	**492**		**192**
Profit before taxation	**2,479**	**16,607**	**24,200**	**(18,162)**	**25,124**
Taxation	**583**	**20**	**7,762**		**8,365**
Profit for the year	**1,896**	**16,587**	**16,438**	**(18,162)**	**16,759**
Attributable to					
BP shareholders	**1,896**	**16,587**	**16,257**	**(18,162)**	**16,578**
Minority interest			**181**		**181**
	1,896	**16,587**	**16,438**	**(18,162)**	**16,759**

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44. Condensed consolidating information on certain US subsidiaries continued
Income statement continued

					$ million
For the year ended 31 December					2008
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	6,782		361,143	(6,782)	361,143
Earnings from jointly controlled entities after interest and tax			3,023		3,023
Earnings from associates after interest and tax			798		798
Equity-accounted income of subsidiaries after interest and tax	469	20,295		(20,764)	
Interest and other revenues	514	173	1,025	(976)	736
Gains on sale of businesses and fixed assets			1,353		1,353
Total revenues and other income	7,765	20,468	367,342	(28,522)	367,053
Purchases	895		272,869	(6,782)	266,982
Production and manufacturing expenses	1,083		25,673		26,756
Production and similar taxes	2,343		6,610		8,953
Depreciation, depletion and amortization	365		10,620		10,985
Impairment and losses on sale of businesses and fixed assets			1,733		1,733
Exploration expense			882		882
Distribution and administration expenses	22	28	15,469	(107)	15,412
Fair value loss on embedded derivatives			111		111
Profit before interest and taxation	3,057	20,440	33,375	(21,633)	35,239
Finance costs	158	169	2,089	(869)	1,547
Net finance (income) expense relating to pensions and other post-retirement benefits		(822)	231		(591)
Profit before taxation	2,899	21,093	31,055	(20,764)	34,283
Taxation	944	(64)	11,737		12,617
Profit for the year	1,955	21,157	19,318	(20,764)	21,666
Attributable to					
BP shareholders	1,955	21,157	18,809	(20,764)	21,157
Minority interest			509		509

	1,955	21,157	19,318	(20,764)	21,666

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44. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

For the year ended 31 December					$ million 2007
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	5,243		284,365	(5,243)	284,365
Earnings from jointly controlled entities after interest and tax			3,135		3,135
Earnings from associates after interest and tax			697		697
Equity-accounted income of subsidiaries after interest and tax	586	21,201		(21,787)	
Interest and other revenues	758	205	1,166	(1,375)	754
Gains on sale of businesses and fixed assets	1		2,486		2,487
Total revenues and other income	6,588	21,406	291,849	(28,405)	291,438
Purchases	650		205,359	(5,243)	200,766
Production and manufacturing expenses	897		23,328		24,225
Production and similar taxes	1,052		4,651		5,703
Depreciation, depletion and amortization	388		10,191		10,579
Impairment and losses on sale of businesses and fixed assets			1,679		1,679
Exploration expense			756		756
Distribution and administration expenses	22	921	14,536	(108)	15,371
Fair value loss on embedded derivatives			7		7
Profit before interest and taxation	3,579	20,485	31,342	(23,054)	32,352
Finance costs	49	381	2,230	(1,267)	1,393
Net finance (income) expense relating to pensions and other post-retirement benefits		(820)	168		(652)
Profit before taxation	3,530	20,924	28,944	(21,787)	31,611
Taxation	1,055	79	9,308		10,442
Profit for the year	2,475	20,845	19,636	(21,787)	21,169
Attributable to					
BP shareholders	2,475	20,845	19,312	(21,787)	20,845
Minority interest			324		324
	2,475	20,845	19,636	(21,787)	21,169

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44. Condensed consolidating information on certain US subsidiaries continued
Balance sheet

					$ million
At 31 December					**2009**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Non-current assets					
Property, plant and equipment	**7,366**		**100,909**		**108,275**
Goodwill			**8,620**		**8,620**
Intangible assets	**321**		**11,227**		**11,548**
Investments in jointly controlled entities			**15,296**		**15,296**
Investments in associates		**2**	**12,961**		**12,963**
Other investments			**1,567**		**1,567**
Subsidiaries equity-accounted basis	**4,424**	**101,760**		**(106,184)**	
Fixed assets	**12,111**	**101,762**	**150,580**	**(106,184)**	**158,269**
Loans	**283**	**1,178**	**5,490**	**(5,912)**	**1,039**
Other receivables			**1,729**		**1,729**
Derivative financial instruments			**3,965**		**3,965**
Prepayments			**1,407**		**1,407**
Deferred tax assets			**516**		**516**
Defined benefit pension plan surpluses		**1,071**	**319**		**1,390**
	12,394	**104,011**	**164,006**	**(112,096)**	**168,315**
Current assets					
Loans			**249**		**249**
Inventories	**221**		**22,384**		**22,605**
Trade and other receivables	**18,529**	**30,707**	**35,852**	**(55,557)**	**29,531**
Derivative financial instruments			**4,967**		**4,967**
Prepayments	**8**	**2**	**1,743**		**1,753**
Current tax receivable			**209**		**209**
Cash and cash equivalents	**(22)**	**28**	**8,333**		**8,339**
	18,736	**30,737**	**73,737**	**(55,557)**	**67,653**

Total assets	**31,130**	**134,748**	**237,743**	**(167,653)**	**235,968**
Current liabilities					
Trade and other payables	**4,662**	**2,374**	**83,725**	**(55,557)**	**35,204**
Derivative financial instruments			**4,681**		**4,681**
Accruals		**27**	**6,175**		**6,202**
Finance debt	**55**		**9,054**		**9,109**
Current tax payable	**172**		**2,292**		**2,464**
Provisions			**1,660**		**1,660**
	4,889	**2,401**	**107,587**	**(55,557)**	**59,320**
Non-current liabilities					
Other payables	**229**	**4,254**	**4,627**	**(5,912)**	**3,198**
Derivative financial instruments			**3,474**		**3,474**
Accruals		**74**	**629**		**703**
Finance debt			**25,518**		**25,518**
Deferred tax liabilities	**1,872**	**149**	**16,641**		**18,662**
Provisions	**1,048**		**11,922**		**12,970**
Defined benefit pension plan and other post-retirement benefit plan deficits			**10,010**		**10,010**
	3,149	**4,477**	**72,821**	**(5,912)**	**74,535**
Total liabilities	**8,038**	**6,878**	**180,408**	**(61,469)**	**133,855**
Net assets	**23,092**	**127,870**	**57,335**	**(106,184)**	**102,113**
Equity					
BP shareholders equity	**23,092**	**127,870**	**56,835**	**(106,184)**	**101,613**
Minority interest			**500**		**500**
Total equity	**23,092**	**127,870**	**57,335**	**(106,184)**	**102,113**

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Notes on financial statements

44. Condensed consolidating information on certain US subsidiaries continued
Balance sheet continued

At 31 December	Issuer	Guarantor			$ million 2008
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	6,959		96,241		103,200
Goodwill			9,878		9,878
Intangible assets	243		10,017		10,260
Investments in jointly controlled entities			23,826		23,826
Investments in associates		2	3,998		4,000
Other investments			855		855
Subsidiaries equity-accounted basis	3,585	111,730		(115,315)	
Fixed assets	10,787	111,732	144,815	(115,315)	152,019
Loans[a]	354	1,174	1,393	(1,926)	995
Other receivables			710		710
Derivative financial instruments			5,054		5,054
Prepayments			1,338		1,338
Defined benefit pension plan surpluses		1,516	222		1,738
	11,141	114,422	153,532	(117,241)	161,854
Current assets					
Loans			168		168
Inventories	198		16,623		16,821
Trade and other receivables[a]	18,302	6,129	35,745	(30,915)	29,261
Derivative financial instruments			8,510		8,510
Prepayments	37		3,013		3,050
Current tax receivable			377		377
Cash and cash equivalents	(10)	11	8,196		8,197
	18,527	6,140	72,632	(30,915)	66,384
Total assets	29,668	120,562	226,164	(148,156)	228,238

Current liabilities					
Trade and other payables	5,070	2,602	57,032	(31,060)	33,644
Derivative financial instruments			8,977		8,977
Accruals		7	6,736		6,743
Finance debt	55		15,685		15,740
Current tax payable	162		2,982		3,144
Provisions			1,545		1,545
	5,287	2,609	92,957	(31,060)	69,793
Non-current liabilities					
Other payables	398	33	4,430	(1,781)	3,080
Derivative financial instruments			6,271		6,271
Accruals		47	737		784
Finance debt			17,464		17,464
Deferred tax liabilities	1,630	322	14,246		16,198
Provisions	1,074		11,034		12,108
Defined benefit pension plan and other post-retirement benefit plan deficits			10,431		10,431
	3,102	402	64,613	(1,781)	66,336
Total liabilities	8,389	3,011	157,570	(32,841)	136,129
Net assets	21,279	117,551	68,594	(115,315)	92,109
Equity					
BP shareholders equity	21,279	117,551	67,788	(115,315)	91,303
Minority interest			806		806
Total equity	21,279	117,551	68,594	(115,315)	92,109

[a]Within Non-current assets Loans, the amount of loans receivable by BP Exploration (Alaska) Inc. (BPXA) has been increased by $145 million from the amounts previously reported and within Current liabilities Trade and other payables, the amount of other payables of BPXA has been increased by $145 million to better reflect the commercial relationship between BPXA and certain other BP subsidiaries.

Notes on financial statements

44. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

	Issuer	Guarantor			$ million 2009
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Net cash provided by operating activities	**1,022**	**14,514**	**47,466**	**(35,286)**	**27,716**
Net cash used in investing activities	**(935)**	**(4,227)**	**(12,971)**		**(18,133)**
Net cash used in financing activities	**(99)**	**(10,270)**	**(34,468)**	**35,286**	**(9,551)**
Currency translation differences relating to cash and cash equivalents			**110**		**110**
(Decrease) increase in cash and cash equivalents	**(12)**	**17**	**137**		**142**
Cash and cash equivalents at beginning of year	**(10)**	**11**	**8,196**		**8,197**
Cash and cash equivalents at end of year	**(22)**	**28**	**8,333**		**8,339**

	Issuer	Guarantor			$ million 2008
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities[a]	1,105	12,665	41,600	(17,275)	38,095
Net cash used in investing activities	(896)		(21,871)		(22,767)
Net cash used in financing activities[a]	(209)	(12,898)	(14,677)	17,275	(10,509)
Currency translation differences relating to cash and cash equivalents			(184)		(184)
(Decrease) increase in cash and cash equivalents		(233)	4,868		4,635
Cash and cash equivalents at beginning of year	(10)	244	3,328		3,562
Cash and cash equivalents at end of year	(10)	11	8,196		8,197

[a]Net cash provided by operating activities and net cash used in financing activities for BP Exploration (Alaska) Inc. have both been reduced by $5,688 million from the amounts previously reported to better reflect the substance of the commercial relationship between BP Exploration (Alaska) Inc. and certain other BP subsidiaries.

					$ million 2007
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities[b]	716	15,403	25,195	(16,605)	24,709
Net cash used in investing activities	(532)	1	(14,306)		(14,837)
Net cash used in financing activities[b]	(189)	(15,139)	(10,312)	16,605	(9,035)
Currency translation differences relating to cash and cash equivalents			135		135
(Decrease) increase in cash and cash equivalents	(5)	265	712		972
Cash and cash equivalents at beginning of year	(5)	(21)	2,616		2,590
Cash and cash equivalents at end of year	(10)	244	3,328		3,562

[b]Net cash provided by operating activities and net cash used in financing activities for BP Exploration (Alaska) Inc. have both been reduced by $2,356 million from the amounts previously reported to better reflect the substance of the commercial relationship between BP Exploration (Alaska) Inc. and certain other BP subsidiaries.

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Supplementary information on oil and natural gas (unaudited)

Supplementary information on oil and natural gas (unaudited)
The regional analysis presented below is on a continent basis, with separate disclosure for countries that contain 15% or more of the total proved reserves (for subsidiaries plus equity-accounted entities), in accordance with revised SEC and FASB requirements. The comparative information for 2008 and 2007 is also presented on this basis. For 2009, where relevant, information for equity-accounted entities is provided in the same level of detail as for subsidiaries. Also for 2009, proved reserves are based on revised SEC definitions.

Oil and gas reserves certain definitions

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

Proved oil and gas reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Undeveloped oil and gas reserves

Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be 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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Developed oil and gas reserves

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For details on BP s proved reserves and production compliance and governance processes, see pages 20 to 22.

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Supplementary information on oil and natural gas (unaudited)

Oil and natural gas exploration and production activities

$ million
2009

	Europe		**North America**		**South America**	**Africa**	**Asia**		**Australasia**	**Total**
	UK	**Rest of Europe**	**US**	**Rest of North America**			**Russia**	**Rest of Asia**		
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	**35,096**	**6,644**	**64,366**	**3,967**	**8,346**	**24,476**		**10,900**	**2,894**	**156,689**
Unproved properties	**752**		**5,464**	**147**	**198**	**2,377**		**733**	**1,039**	**10,710**
	35,848	**6,644**	**69,830**	**4,114**	**8,544**	**26,853**		**11,633**	**3,933**	**167,399**
Accumulated depreciation	**26,794**	**3,306**	**31,728**	**2,309**	**4,837**	**12,492**		**4,798**	**1,038**	**87,302**
Net capitalized costs	**9,054**	**3,338**	**38,102**	**1,805**	**3,707**	**14,361**		**6,835**	**2,895**	**80,097**
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	**179**		**(17)**					**306**		**468**
Unproved	**(1)**		**370**	**1**		**18**			**10**	**398**
	178		**353**	**1**		**18**		**306**	**10**	**866**
Exploration and appraisal costs[d]	**183**		**1,377**	**79**	**78**	**712**	**8**	**315**	**53**	**2,805**
Development	**751**	**1,054**	**4,208**	**386**	**453**	**2,707**		**560**	**277**	**10,396**
Total costs	**1,112**	**1,054**	**5,938**	**466**	**531**	**3,437**	**8**	**1,181**	**340**	**14,067**
Results of operations for the year ended 31 December										

Sales and other operating revenues[e]										
Third parties	**2,239**	**68**	**4,759**	**99**	**1,525**	**1,846**		**636**	**785**	**11,957**
Sales between businesses	**2,482**	**809**	**11,313**	**484**	**1,409**	**5,313**		**6,257**	**726**	**28,793**
	4,721	**877**	**16,072**	**583**	**2,934**	**7,159**		**6,893**	**1,511**	**40,750**
Exploration expenditure	**59**		**663**	**80**	**16**	**219**	**8**	**49**	**22**	**1,116**
Production costs	**1,243**	**164**	**2,821**	**284**	**395**	**908**	**15**	**361**	**70**	**6,261**
Production taxes	**(3)**		**649**	**1**	**220**			**2,854**	**72**	**3,793**
Other costs (income)[f]	**(1,259)**	**51**	**2,353**	**145**	**184**	**144**	**76**	**967**	**178**	**2,839**
Depreciation, depletion and amortization	**1,148**	**185**	**3,857**	**170**	**697**	**2,041**		**757**	**96**	**8,951**
Impairments and (gains) losses on sale of businesses and fixed assets	**(122)**	**(7)**	**(208)**		**(11)**	**(1)**		**(702)**[j]		**(1,051)**
	1,066	**393**	**10,135**	**680**	**1,501**	**3,311**	**99**	**4,286**	**438**	**21,909**
Profit before taxation[g]	**3,655**	**484**	**5,937**	**(97)**	**1,433**	**3,848**	**(99)**	**2,607**	**1,073**	**18,841**
Allocable taxes	**1,568**	**76**	**1,902**	**(58)**	**916**	**1,517**	**(25)**	**682**	**2**	**6,580**
Results of operations	**2,087**	**408**	**4,035**	**(39)**	**517**	**2,331**	**(74)**	**1,925**	**1,071**	**12,261**

Exploration and Production segment replacement cost profit before interest and tax

Exploration and production activities subsidiaries (as above)	**3,655**	**484**	**5,937**	**(97)**	**1,433**	**3,848**	**(99)**	**2,607**	**1,073**	**18,841**
Midstream activities subsidiaries[h]	**925**	**17**	**719**	**833**	**17**	**(27)**	**(37)**	**518**	**(315)**	**2,650**
Equity-accounted entities[i]		**5**	**29**	**134**	**630**	**56**	**1,924**	**531**		**3,309**
Total replacement cost profit before interest and tax	**4,580**	**506**	**6,685**	**870**	**2,080**	**3,877**	**1,788**	**3,656**	**758**	**24,800**

[a]These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGL s in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.

[b]Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c]Includes costs capitalized as a result of asset exchanges.

[d]Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[e]Presented net of transportation costs, purchases and sales taxes.

[f]Includes property taxes, other government take and the fair value gain on embedded derivatives of $663 million. The UK region includes a $783 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

[g]Excludes the unwinding of the discount on provisions and payables amounting to $308 million which is included in finance costs in the group income statement.

[h]Midstream activities exclude inventory holding gains and losses.

[i]The profits of equity-accounted entities are included after interest and tax.

[j]Includes the gain on disposal of upstream assets associated with our sale of our 46% stake in LukArco (see Note 3).

Supplementary information on oil and natural gas (unaudited)

Oil and natural gas exploration and production activities continued

$ million

2009

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties					5,789		13,266	2,259		21,314
Unproved properties				1,378	197		737			2,312
				1,378	5,986		14,003	2,259		23,626
Accumulated depreciation					2,084		5,550	1,739		9,373
Net capitalized costs				1,378	3,902		8,453	520		14,253
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved										
Unproved					31		10			41
					31		10			41
Exploration and appraisal costs[d]					21		77	3		101
Development				30	538		1,182	246		1,996
Total costs				30	590		1,269	249		2,138

Results of operations for the year ended 31 December

Sales and other operating revenues[e]								
Third parties				**1,977**		**4,919**	**351**	**7,247**
Sales between businesses						**2,838**		**2,838**
				1,977		**7,757**	**351**	**10,085**
Exploration expenditure				**23**		**37**		**60**
Production costs				**354**		**1,428**	**159**	**1,941**
Production taxes				**702**		**2,597**		**3,299**
Other costs (income)				**(69)**		**12**	**(2)**	**(59)**
Depreciation, depletion and amortization				**281**		**1,073**	**274**	**1,628**
Impairments and (gains) losses on sale of businesses and fixed assets						**72**		**72**
				1,291		**5,219**	**431**	**6,941**
Profit before taxation				**686**		**2,538**	**(80)**	**3,144**
Allocable taxes				**270**		**501**		**771**
Results of operations				**416**		**2,037**	**(80)**	**2,373**
Exploration and production activities equity-accounted entities (as above)				**416**		**2,037**	**(80)**	**2,373**
Midstream and other activities after tax[f]	**5**	**29**	**134**	**214**	**56**	**(113)**	**611**	**936**
Total replacement cost profit after interest and tax	**5**	**29**	**134**	**630**	**56**	**1,924**	**531**	**3,309**

[a]These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.

[b]Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c]Includes costs capitalized as a result of asset exchanges.

[d]Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[e]Presented net of transportation costs, purchases and sales taxes.

[f]Includes interest, minority interest and the net results of equity-accounted entities of equity-accounted entities.

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Supplementary information on oil and natural gas (unaudited)

Oil and natural gas exploration and production activities continued

$ million

2008

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	34,614	5,507	59,918	3,517	7,934	21,563		10,689	2,581	146,323
Unproved properties	626		5,006	165	134	2,011		465	1,018	9,425
	35,240	5,507	64,924	3,682	8,068	23,574		11,154	3,599	155,748
Accumulated depreciation	26,564	3,125	28,511	2,141	4,217	10,451		4,395	945	80,349
Net capitalized costs	8,676	2,382	36,413	1,541	3,851	13,123		6,759	2,654	75,399

The group s share of equity-accounted entities net capitalized costs at 31 December 2008 was $13,393 million.

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	Total
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved			1,374	2				136		1,512
Unproved	4		2,942					41		2,987
	4		4,316	2				177		4,499
Exploration and appraisal costs[d]	137		862	33	90	838	12	269	49	2,290
Development	907	695	4,914	309	768	2,966		859	349	11,767
Total costs	1,048	695	10,092	344	858	3,804	12	1,305	398	18,556

The group s share of equity-accounted entities costs incurred in 2008 was $3,259 million: in Russia $1,921 million, South America $1,039 million, and Rest of Asia $299 million.

Results of operations for the year ended 31 December

Sales and other operating revenues[e]										
Third parties	3,865	105	8,010	147	3,339	3,745		1,186	860	21,257
Sales between businesses	4,374	1,416	15,610	1,237	2,605	6,022		11,249	1,171	43,684
	8,239	1,521	23,620	1,384	5,944	9,767		12,435	2,031	64,941
Exploration expenditure	121	1	305	32	30	213	14	140	26	882
Production costs	1,357	150	3,002	289	429	875	18	485	62	6,667
Production taxes[f]	503		2,603	2	358			5,510	110	9,086
Other costs (income)[f g]	(28)	(43)	3,440	343	198	(122)[k]	196	2,064	226	6,274
Depreciation, depletion and amortization	1,049	199	2,729	181	730	2,120		788	87	7,883
Impairments and (gains) losses on sale of businesses and fixed assets			308	2	4	8		219		541
	3,002	307	12,387	849	1,749	3,094	228	9,206	511	31,333
Profit before taxation[h]	5,237	1,214	11,233	535	4,195	6,673	(228)	3,229	1,520	33,608
Allocable taxes	2,280	883	3,857	205	2,218	2,672	(36)	984	513	13,576
Results of operations	2,957	331	7,376	330	1,977	4,001	(192)	2,245	1,007	20,032

The group s share of equity-accounted entities results of operations (including the group s share of total TNK-BP results) in 2008 w profit of $2,793 million after deducting interest of $355 million, taxation of $1,217 million and minority interest of $169 million.

Exploration and Production segment replacement cost profit before interest and tax

Exploration and production activities										
Subsidiaries (as above)	5,237	1,214	11,233	535	4,195	6,673	(228)	3,229	1,520	33,608
Equity-accounted entities	(1)		1	40	304	(1)	2,259	191		2,793
Midstream activities[i j]	743	16	490	673	274	112		(272)	(129)	1,907
Total replacement cost profit before interest and tax	5,979	1,230	11,724	1,248	4,773	6,784	2,031	3,148	1,391	38,308

[a] These tables contain information relating to oil and natural gas exploration and production activities. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline.

Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola. The group s share of equity-accounted entities activities are excluded from the tables and included in the footnotes, with the exception of Abu Dhabi production taxes, which are included in the results of operations above.

[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c] Includes costs capitalized as a result of asset exchanges.

[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[e] Presented net of transportation costs, purchases and sales taxes.

[f] Comparative figures have been restated to include in Production taxes amounts previously reported within Other costs (income) amounting to $2,427 million.

[g] Includes property taxes, other government take and the fair value loss on embedded derivatives of $102 million. The UK region includes a $499 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

[h] Excludes the unwinding of the discount on provisions and payables amounting to $285 million which is included in finance costs in the group income statement.

[i] Includes a $517 million write-down of our investment in Rosneft based on its quoted market price at the end of the year.

[j] Midstream activities exclude inventory holding gains and losses.

[k] Includes $367 million previously reported within the Other region.

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Supplementary information on oil and natural gas (unaudited)

Oil and natural gas exploration and production activities continued

$ mill

20

	Europe		North America		South America	Africa	Asia		Australasia	To
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	34,774	4,925	53,079	3,261	7,366	18,333		9,629	1,495	132,8
Unproved properties	606		1,660	182	115	1,533	4	536	1,001	5,6
	35,380	4,925	54,739	3,443	7,481	19,866	4	10,165	2,496	138,4
Accumulated depreciation	25,515	2,925	25,500	1,968	3,560	8,315		3,638	423	71,8
Net capitalized costs	9,865	2,000	29,239	1,475	3,921	11,551	4	6,527	2,073	66,6

The group s share of equity-accounted entities net capitalized costs at 31 December 2007 was $11,787 million.

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia	Rest of Asia	Australasia	To
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved			245					232		4
Unproved			54	16		321		126		5
			299	16		321		358		9
Exploration and appraisal costs[d]	209	16	646	40	32	677	119	118	35	1,8
Development	804	443	3,861	240	817	2,634		1,109	245	10,1
Total costs	1,013	459	4,806	296	849	3,632	119	1,585	280	13,0

The group s share of equity-accounted entities costs incurred in 2007 was $2,552 million: in Russia $1,787 million, South Ar
$569 million, and Rest of Asia $196 million.

Results of operations for the year ended 31 December

Sales and other operating revenues[e]										
Third parties	4,503	434	1,436	147	1,995	2,219		1,388	681	12,8
Sales between businesses	2,260	902	14,353	868	2,274	3,223		10,137	816	34,8
	6,763	1,336	15,789	1,015	4,269	5,442		11,525	1,497	47,6
Exploration expenditure	46		252	57	77	183	116	18	7	7
Production costs	1,658	147	2,782	267	503	637	2	470	64	6,5
Production taxes[f]	227	3	1,260	1	272			3,914	56	5,7
Other costs (income)[f g]	(419)	123	2,505	237	158	224[j]	169	1,316	366	4,6
Depreciation, depletion and amortization	1,569	207	2,118	169	653	1,372		1,148	52	7,2
Impairments and (gains) losses on sale of businesses and fixed assets	112	(534)	(413)	(38)	(5)	(76)				(9
	3,193	(54)	8,504	693	1,658	2,340	287	6,866	545	24,0
Profit before taxation[h]	3,570	1,390	7,285	322	2,611	3,102	(287)	4,659	952	23,6
Allocable taxes	1,664	611	2,560	35	1,167	1,462	3	1,133	267	8,9
Results of operations	1,906	779	4,725	287	1,444	1,640	(290)	3,526	685	14,7

The group s share of equity-accounted entities results of operations (including the group s share of total TNK-BP results) in
was a profit of $2,704 million after deducting interest of $401 million, taxation of $1,355 million and minority interest of
$215 million.

Exploration and Production segment replacement cost profit before interest and tax

Exploration and production activities										
Subsidiaries (as above)	3,570	1,390	7,285	322	2,611	3,102	(287)	4,659	952	23,6
Equity-accounted entities			1	(33)	414		2,292	30		2,7
Midstream activities[i]	15	12	643	626	13	96	(112)	38	(37)	1,2
Total replacement cost profit before interest and tax	3,585	1,402	7,929	915	3,038	3,198	1,893	4,727	915	27,6

[a]These tables contain information relating to oil and natural gas exploration and production activities. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of

marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia. The group s share of equity-accounted entities activities are excluded from the tables and included in the footnotes with the exception of the Abu Dhabi operations which are included in the results of operations above.

[b]Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c]Includes costs capitalized as a result of asset exchanges.

[d]Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[e]Presented net of transportation costs, purchases and sales taxes.

[f]Comparative figures have been restated to include in Production taxes amounts previously reported within Other costs (income) amounting to $1,690 million.

[g]Includes property taxes, other government take and the fair value gain on embedded derivatives of $47 million. The UK region includes a $409 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

[h]Excludes the unwinding of the discount on provisions and payables amounting to $179 million which is included in finance costs in the group income statement.

[i]Midstream activities exclude inventory holding gains and losses.

[j]Includes $24 million previously reported within the Other region.

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Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves

										million barrels
Crude oil[a]										**2009**
	Europe		**North America**		**South America**	**Africa**	**Asia**		**Australasia**	**Total**
	UK	**Rest of Europe**	**US[e]**	**Rest of North America**			**Russia**	**Rest of Asia**		
Subsidiaries										
At 1 January 2009										
Developed	**410**	**81**	**1,717**	**11**	**47**	**464**		**195**	**56**	**2,981**
Undeveloped	**119**	**194**	**1,273**	**1**	**55**	**496**		**488**	**58**	**2,684**
	529	**275**	**2,990**	**12**	**102**	**960**		**683**	**114**	**5,665**
Changes attributable to										
Revisions of previous estimates	**7**	**(1)**	**165**	**2**	**18**	**(121)**		**(128)**	**3**	**(55)**
Improved recovery	**42**	**7**	**82**		**7**	**32**		**31**	**2**	**203**
Purchases of reserves-in-place	**1**							**1**		**2**
Discoveries and extensions	**184**		**73**			**114**			**7**	**378**
Production[b]	**(61)**	**(14)**	**(237)**	**(2)**	**(22)**	**(109)**		**(45)**	**(11)**	**(501)**
Sales of reserves-in-place	**(8)**							**(26)**		**(34)**
	165	**(8)**	**83**		**3**	**(84)**		**(167)**	**1**	**(7)**
At 31 December 2009[c]										
Developed	**403**	**83**	**1,862**	**11**	**49**	**422**		**182**	**58**	**3,070**
Undeveloped	**291**	**184**	**1,211**	**1**	**56**	**454**		**334**	**57**	**2,588**
	694	**267**	**3,073**	**12**	**105**	**876**		**516**	**115**	**5,658**
Equity-accounted entities (BP share)[f]										
At 1 January 2009										
Developed					**399**		**2,227**	**499**		**3,125**
Undeveloped					**409**	**11**	**944**	**199**		**1,563**
					808	**11**	**3,171**	**698**		**4,688**

Changes attributable to										
Revisions of previous estimates					**2**	**(2)**	**590**	**(28)**		**562**
Improved recovery					**50**		**8**			**58**
Purchases of reserves-in-place										
Discoveries and extensions					**3**		**87**			**90**
Production					**(37)**		**(307)**	**(71)**		**(415)**
Sales of reserves-in-place					**(14)**			**(116)**		**(130)**
					4	**(2)**	**378**	**(215)**		**165**
At 31 December 2009[d]										
Developed					**407**		**2,351**	**363**		**3,121**
Undeveloped					**405**	**9**	**1,198**	**120**		**1,732**
					812	**9**	**3,549**	**483**		**4,853**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	**410**	**81**	**1,717**	**11**	**446**	**464**	**2,227**	**694**	**56**	**6,106**
Undeveloped	**119**	**194**	**1,273**	**1**	**464**	**507**	**944**	**687**	**58**	**4,247**
	529	**275**	**2,990**	**12**	**910**	**971**	**3,171**	**1,381**	**114**	**10,353**
At 31 December 2009										
Developed	**403**	**83**	**1,862**	**11**	**456**	**422**	**2,351**	**545**	**58**	**6,191**
Undeveloped	**291**	**184**	**1,211**	**1**	**461**	**463**	**1,198**	**454**	**57**	**4,320**
	694	**267**	**3,073**	**12**	**917**	**885**	**3,549**	**999**	**115**	**10,511**

[a] Crude oil includes NGLs and condensate. 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.

[b] Excludes NGLs from processing plants in which an interest is held of 26 thousand barrels a day.

[c] Includes 819 million barrels of NGLs. Also includes 23 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d] Includes 20 million barrels of NGLs. Also includes 243 million barrels of crude oil in respect of the 6.86% minority interest in TNK-BP.

[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 68 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.

[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

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Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves continued

Natural gas[a]										billion cubic feet 2009
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2009										
Developed	1,822	61	9,059	659	3,316	1,050		1,102	1,887	18,956
Undeveloped	582	402	5,473	468	7,434	1,382		1,308	4,000	21,049
	2,404	463	14,532	1,127	10,750	2,432		2,410	5,887	40,005
Changes attributable to										
Revisions of previous estimates	(114)	(8)	549	43	322	270		(231)	22	853
Improved recovery	34		550	5	322	49		82	75	1,117
Purchases of reserves-in-place	159							31		190
Discoveries and extensions	150		496	94	105	59			531	1,435
Production[b]	(243)	(9)	(907)	(100)	(929)	(249)		(241)	(189)	(2,867)
Sales of reserves-in-place	(118)		(4)					(223)		(345)
	(132)	(17)	684	42	(180)	129		(582)	439	383
At 31 December 2009[c]										
Developed	1,602	49	9,583	716	3,177	1,107		1,579	3,219	21,032
Undeveloped	670	397	5,633	453	7,393	1,454		249	3,107	19,356
	2,272	446	15,216	1,169	10,570	2,561		1,828	6,326	40,388
Equity-accounted entities (BP share)[e]										
At 1 January 2009										
Developed					1,498		1,560	176		3,234
Undeveloped					1,023	182	653	111		1,969
					2,521	182	2,213	287		5,203
Changes attributable to										

Revisions of previous estimates					**(26)**	**(17)**	**204**	**(19)**		**142**
Improved recovery					**314**		**1**	**4**		**319**
Purchases of reserves-in-place										
Discoveries and extensions					**6**		**23**			**29**
Production[b]					**(165)**		**(219)**	**(25)**		**(409)**
Sales of reserves-in-place					**(388)**			**(154)**		**(542)**
					(259)	**(17)**	**9**	**(194)**		**(461)**
At 31 December 2009[d]										
Developed					**1,252**		**1,703**	**80**		**3,035**
Undeveloped					**1,010**	**165**	**519**	**13**		**1,707**
					2,262	**165**	**2,222**	**93**		**4,742**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	**1,822**	**61**	**9,059**	**659**	**4,814**	**1,050**	**1,560**	**1,278**	**1,887**	**22,190**
Undeveloped	**582**	**402**	**5,473**	**468**	**8,457**	**1,564**	**653**	**1,419**	**4,000**	**23,018**
	2,404	**463**	**14,532**	**1,127**	**13,271**	**2,614**	**2,213**	**2,697**	**5,887**	**45,208**
At 31 December 2009										
Developed	**1,602**	**49**	**9,583**	**716**	**4,429**	**1,107**	**1,703**	**1,659**	**3,219**	**24,067**
Undeveloped	**670**	**397**	**5,633**	**453**	**8,403**	**1,619**	**519**	**262**	**3,107**	**21,063**
	2,272	**446**	**15,216**	**1,169**	**12,832**	**2,726**	**2,222**	**1,921**	**6,326**	**45,130**

[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.

[b] Includes 195 billion cubic feet of natural gas consumed in operations, 164 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities and excludes 16 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.

[c] Includes 3,068 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d] Includes 131 billion cubic feet of natural gas in respect of the 5.79% minority interest in TNK-BP.

[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

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Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves continued

million barrels

Crude oil[a]										2008
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[e]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2008										
Developed	414	105	1,882	13	102	256		121	44	2,937
Undeveloped	123	169	1,265	1	202	350		372	73	2,555
	537	274	3,147	14	304	606		493	117	5,492
Changes attributable to										
Revisions of previous estimates	16	(11)	(212)	1	7	264		194	5	264
Improved recovery	39	28	182		8	18		43	3	321
Purchases of reserves-in-place										
Discoveries and extensions			64		5	173				242
Production[b]	(63)	(16)	(191)	(3)	(23)	(101)		(47)	(11)	(455)
Sales of reserves-in-place					(199)					(199)
	(8)	1	(157)	(2)	(202)	354		190	(3)	173
At 31 December 2008[c]										
Developed	410	81	1,717	11	47	464		195	56	2,981
Undeveloped	119	194	1,273	1	55	496		488	58	2,684
	529	275	2,990	12	102	960		683	114	5,665
Equity-accounted entities (BP share)[f]										
At 1 January 2008										
Developed					328		2,094	574		2,996
Undeveloped					243		1,137	205		1,585
					571		3,231	779		4,581

Changes attributable to										
Revisions of previous estimates					(3)	11	217	(1)		224
Improved recovery					62					62
Purchases of reserves-in-place					199					199
Discoveries and extensions					13		26			39
Production					(34)		(302)	(80)		(416)
Sales of reserves-in-place							(1)			(1)
					237	11	(60)	(81)		107
At 31 December 2008[d]										
Developed					399		2,227	499		3,125
Undeveloped					409	11	944	199		1,563
					808	11	3,171	698		4,688
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2008										
Developed	414	105	1,882	13	430	256	2,094	695	44	5,933
Undeveloped	123	169	1,265	1	445	350	1,137	577	73	4,140
	537	274	3,147	14	875	606	3,231	1,272	117	10,073
At 31 December 2008										
Developed	410	81	1,717	11	446	464	2,227	694	56	6,106
Undeveloped	119	194	1,273	1	464	507	944	687	58	4,247
	529	275	2,990	12	910	971	3,171	1,381	114	10,353

[a]Crude oil includes NGLs and condensate. 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.

[b]Excludes NGLs from processing plants in which an interest is held of 19 thousand barrels a day.

[c]Includes 807 million barrels of NGLs. Also includes 21 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d]Includes 36 million barrels of NGLs. Also includes 216 million barrels of crude oil in respect of the 6.80% minority interest in TNK-BP.

[e]Proved reserves in the Prudhoe Bay field in Alaska include an estimated 54 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.

[f]Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

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Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	2008 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2008										
Developed	2,049	63	10,670	608	3,075	990		1,270	1,135	19,860
Undeveloped	553	410	4,705	421	7,973	1,410		1,269	4,529	21,270
	2,602	473	15,375	1,029	11,048	2,400		2,539	5,664	41,130
Changes attributable to										
Revisions of previous estimates	23	(8)	(2,063)	51	(456)	142			361	(1,950)
Improved recovery	77	9	1,322	16	159	6		108	2	1,699
Purchases of reserves-in-place			183							183
Discoveries and extensions			549	125	948	82		37		1,741
Production[b]	(298)	(11)	(834)	(94)	(946)	(198)		(274)	(140)	(2,795)
Sales of reserves-in-place					(3)					(3)
	(198)	(10)	(843)	98	(298)	32		(129)	223	(1,125)
At 31 December 2008[c]										
Developed	1,822	61	9,059	659	3,316	1,050		1,102	1,887	18,956
Undeveloped	582	402	5,473	468	7,434	1,382		1,308	4,000	21,049
	2,404	463	14,532	1,127	10,750	2,432		2,410	5,887	40,005
Equity-accounted entities (BP share)[e]										
At 1 January 2008										
Developed					1,478		808	187		2,473
Undeveloped					831		353	113		1,297
					2,309		1,161	300		3,770

Changes attributable to										
Revisions of previous estimates					(96)	182	1,273	(2)		1,357
Improved recovery					301			11		312
Purchases of reserves-in-place					3					3
Discoveries and extensions					192					192
Production[b]					(188)		(221)	(22)		(431)
Sales of reserves-in-place										
					212	182	1,052	(13)		1,433
At 31 December 2008[d]										
Developed					1,498		1,560	176		3,234
Undeveloped					1,023	182	653	111		1,969
					2,521	182	2,213	287		5,203
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2008										
Developed	2,049	63	10,670	608	4,553	990	808	1,457	1,135	22,333
Undeveloped	553	410	4,705	421	8,804	1,410	353	1,382	4,529	22,567
	2,602	473	15,375	1,029	13,357	2,400	1,161	2,839	5,664	44,900
At 31 December 2008										
Developed	1,822	61	9,059	659	4,814	1,050	1,560	1,278	1,887	22,190
Undeveloped	582	402	5,473	468	8,457	1,564	653	1,419	4,000	23,018
	2,404	463	14,532	1,127	13,271	2,614	2,213	2,697	5,887	45,208

[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.

[b]Includes 193 billion cubic feet of natural gas consumed in operations, 149 billion cubic feet in subsidiaries, 44 billion cubic feet in equity-accounted entities and excludes 17 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.

[c]Includes 3,108 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d]Includes 131 billion cubic feet of natural gas in respect of the 5.92% minority interest in TNK-BP.

[e]Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

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Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves continued

million barrels

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	2007 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2007										
Developed	458	189	1,916	15	115	193		104	51	3,041
Undeveloped	146	97	1,292	2	235	512		487	81	2,852
	604	286	3,208	17	350	705		591	132	5,893
Changes attributable to										
Revisions of previous estimates	(1)	(25)	18		(29)	(133)		(29)	(5)	(204)
Improved recovery	7	1	99		6	12		6		131
Purchases of reserves-in-place			25					8		33
Discoveries and extensions		31	60		1	93			2	187
Production[b]	(73)	(19)	(169)	(3)	(24)	(71)		(83)	(12)	(454)
Sales of reserves-in-place			(94)							(94)
	(67)	(12)	(61)	(3)	(46)	(99)		(98)	(15)	(401)
At 31 December 2007[c]										
Developed	414	105	1,882	13	102	256		121	44	2,937
Undeveloped	123	169	1,265	1	202	350		372	73	2,555
	537	274	3,147	14	304	606		493	117	5,492
Equity-accounted entities (BP share)[d g]										
At 1 January 2007										
Developed					221		2,200	521		2,942
Undeveloped					139		644	163		946
					360		2,844	684		3,888

Changes attributable to										
Revisions of previous estimates					178		413	167		758
Improved recovery					59			1		60
Purchases of reserves-in-place							16			16
Discoveries and extensions					2		283			285
Production					(28)		(304)	(73)		(405)
Sales of reserves-in-place							(21)			(21)
					211		387	95		693
At 31 December 2007[e]										
Developed					328		2,094	574		2,996
Undeveloped					243		1,137	205		1,585
					571		3,231	779		4,581
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2007										
Developed	458	189	1,916	15	336	193	2,200	625	51	5,983
Undeveloped	146	97	1,292	2	374	512	644	650	81	3,798
	604	286	3,208	17	710	705	2,844	1,275	132	9,781
At 31 December 2007										
Developed	414	105	1,882	13	430	256	2,094	695	44	5,933
Undeveloped	123	169	1,265	1	445	350	1,137	577	73	4,140
	537	274	3,147	14	875	606	3,231	1,272	117	10,073

[a]Crude oil includes NGLs and condensate. 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.

[b]Excludes NGLs from processing plants in which an interest is held of 54 thousand barrels a day.

[c]Includes 739 million barrels of NGLs. Also includes 20 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d]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 33mb/d.

[e]Includes 26 million barrels of NGLs. Also includes 210 million barrels of crude oil in respect of the 6.51% minority interest in TNK-BP.

[f]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.

[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

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Supplementary information on oil and natural gas (unaudited)

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a]

	Europe		North America		South America	Africa	Asia		Australasia	2007 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2007										
Developed	1,968	242	10,438	627	3,305	1,032		808	882	19,302
Undeveloped	825	56	4,660	310	8,884	1,675		1,781	4,675	22,866
	2,793	298	15,098	937	12,189	2,707		2,589	5,557	42,168
Changes attributable to										
Revisions of previous estimates	93	(37)	744	(72)	(204)	(146)		(21)	140	497
Improved recovery	15	1	326	32		9		100	16	499
Purchases of reserves-in-place			23					109		132
Discoveries and extensions		293	95	237	12	17			88	742
Production[b]	(299)	(14)	(879)	(98)	(949)	(187)		(238)	(137)	(2,801)
Sales of reserves-in-place		(68)	(32)	(7)						(107)
	(191)	175	277	92	(1,141)	(307)		(50)	107	(1,038)
At 31 December 2007[c]										
Developed	2,049	63	10,670	608	3,075	990		1,270	1,135	19,860
Undeveloped	553	410	4,705	421	7,973	1,410		1,269	4,529	21,270
	2,602	473	15,375	1,029	11,048	2,400		2,539	5,664	41,130
Equity-accounted entities (BP share)[e]										
At 1 January 2007										
Developed					1,460		1,087	222		2,769

Undeveloped					735		184	75		994
					2,195		1,271	297		3,763
Changes attributable to										
Revisions of previous estimates					73		61	9		143
Improved recovery					195			16		211
Purchases of reserves-in-place							8			8
Discoveries and extensions					22					22
Production[b]					(176)		(179)	(22)		(377)
Sales of reserves-in-place										
					114		(110)	3		7
At 31 December 2007[d]										
Developed					1,478		808	187		2,473
Undeveloped					831		353	113		1,297
					2,309		1,161	300		3,770
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2007										
Developed	1,968	242	10,438	627	4,765	1,032	1,087	1,030	882	22,071
Undeveloped	825	56	4,660	310	9,619	1,675	184	1,856	4,675	23,860
	2,793	298	15,098	937	14,384	2,707	1,271	2,886	5,557	45,931
At 31 December 2007										
Developed	2,049	63	10,670	608	4,553	990	808	1,457	1,135	22,333
Undeveloped	553	410	4,705	421	8,804	1,410	353	1,382	4,529	22,567
	2,602	473	15,375	1,029	13,357	2,400	1,161	2,839	5,664	44,900

[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.

[b]Includes 202 billion cubic feet of natural gas consumed in operations, 161 billion cubic feet in subsidiaries, 41 billion cubic feet in equity-accounted entities and excludes 10.9 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.

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

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

[e]Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

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Supplementary information on oil and natural gas (unaudited)

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves

The following tables set out the standardized measure of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group s estimated proved reserves. This information is prepared in compliance with FASB Oil and Gas Disclosures requirements.

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of average crude oil and natural gas prices and exchange rates from the previous 12 months. Furthermore, both proved reserves estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. BP cautions against relying on the information presented because of the highly arbitrary nature of the assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

$ million

										2009
	Europe		**North America**		**South America**	**Africa**	**Asia**		**Australasia**	**Total**
	UK	**Rest of Europe**	**US**	**Rest of North America**			**Russia**	**Rest of Asia**		
At 31 December 2009										
Subsidiaries										
Future cash inflows[a]	**50,800**	**17,700**	**204,000**	**4,900**	**26,400**	**58,400**		**36,100**	**32,500**	**430,800**
Future production cost[b]	**20,000**	**8,000**	**91,300**	**2,700**	**6,700**	**12,000**		**9,200**	**11,000**	**160,900**
Future development cost[b]	**5,000**	**2,500**	**24,900**	**1,000**	**5,600**	**12,200**		**6,400**	**3,100**	**60,700**
Future taxation[c]	**12,900**	**3,700**	**27,300**	**200**	**5,800**	**11,300**		**4,700**	**4,500**	**70,400**
Future net cash flows	**12,900**	**3,500**	**60,500**	**1,000**	**8,300**	**22,900**		**15,800**	**13,900**	**138,800**
10% annual discount[d]	**5,800**	**1,600**	**29,500**	**500**	**3,200**	**9,800**		**6,300**	**7,300**	**64,000**
Standardized measure of discounted future net cash flows[e]	**7,100**	**1,900**	**31,000**	**500**	**5,100**	**13,100**		**9,500**	**6,600**	**74,800**
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]					**37,700**		**96,700**	**30,000**		**164,400**

Future production cost[b]					**17,000**		**65,200**	**25,200**		**107,400**
Future development cost[b]					**4,000**		**10,200**	**3,100**		**17,300**
Future taxation[c]					**5,200**		**4,300**	**100**		**9,600**
Future net cash flows					**11,500**		**17,000**	**1,600**		**30,100**
10% annual discount[d]					**6,800**		**7,900**	**800**		**15,500**
Standardized measure of discounted future net cash flows[g h]					**4,700**		**9,100**	**800**		**14,600**
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	**7,100**	**1,900**	**31,000**	**500**	**9,800**	**13,100**	**9,100**	**10,300**	**6,600**	**89,400**

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

			$ million
	Subsidiaries	**Equity-accounted entities (BP share)**	**Total subsidiaries and equity-accounted entities**
Sales and transfers of oil and gas produced, net of production costs	**(18,900)**	**(3,400)**	**(22,300)**
Previously estimated development costs incurred during the year	**11,700**	**2,100**	**13,800**
Extensions, discoveries and improved recovery, less related costs	**8,500**	**1,600**	**10,100**
Net changes in prices and production cost	**37,200**	**5,900**	**43,100**
Revisions of previous reserves estimates	**(4,300)**	**(200)**	**(4,500)**
Net change in taxation	**(10,600)**	**(1,600)**	**(12,200)**
Future development costs	**(600)**	**900**	**300**
Net change in purchase and sales of reserves-in-place	**(100)**	**(900)**	**(1,000)**
Addition of 10% annual discount	**4,700**	**900**	**5,600**
Total change in the standardized measure during the year[i]	**27,600**	**5,300**	**32,900**

[a]The marker prices used were Brent $59.91/bbl, Henry Hub $3.82/mmBtu.

[b]Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.

[c]Taxation is computed using appropriate year-end statutory corporate income tax rates.

[d]Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.

[e]Minority interest in BP Trinidad and Tobago LLC amounted to $1,300 million.

[f]The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.

[g]Minority interest in TNK-BP amounted to $600 million.

[h]No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.

[i]Total change in the standardized measure during the year includes the effect of exchange rate movements.

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Supplementary information on oil and natural gas (unaudited)

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2008										
Subsidiaries										
Future cash inflows[a]	36,400	13,800	165,800	6,400	26,300	40,400		31,400	24,200	344,700
Future production cost[b]	18,100	6,300	80,400	2,700	7,200	11,600		11,800	10,700	148,800
Future development cost[b]	3,300	2,900	25,600	1,300	7,200	10,900		7,500	3,200	61,900
Future taxation[c]	7,300	2,300	17,500	500	5,500	6,600		2,400	2,800	44,900
Future net cash flows	7,700	2,300	42,300	1,900	6,400	11,300		9,700	7,500	89,100
10% annual discount[d]	2,200	1,200	21,000	1,000	2,900	5,500		4,200	3,900	41,900
Standardized measure of discounted future net cash flows[e]	5,500	1,100	21,300	900	3,500	5,800		5,500	3,600	47,200
Equity-accounted entities (BP share)[g]										
Standardized measure of discounted future net cash flows[h]					3,600		4,800	900		9,300
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[e]	5,500	1,100	21,300	900	7,100	5,800	4,800	6,400	3,600	56,500
At 31 December 2007										
Subsidiaries										

Future cash inflows[a]	72,100	29,500	350,100	7,500	60,200	63,300		55,100	41,900	679,700
Future production cost[b]	27,500	7,500	109,800	3,000	14,900	9,900		9,700	11,600	193,900
Future development cost[b]	4,000	3,300	21,900	700	5,800	8,300		3,900	3,700	51,600
Future taxation[c]	20,200	13,000	71,600	900	20,800	17,100		9,800	8,600	162,000
Future net cash flows	20,400	5,700	146,800	2,900	18,700	28,000		31,700	18,000	272,200
10% annual discount[d]	6,500	2,800	76,000	1,300	8,200	9,400		12,600	9,200	126,000
Standardized measure of discounted future net cash flows[e]	13,900	2,900	70,800	1,600	10,500	18,600		19,100	8,800	146,200
Equity-accounted entities (BP share)[g]										
Standardized measure of discounted future net cash flows[h]					5,000		21,700	3,000		29,700
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[e]	13,900	2,900	70,800	1,600	15,500	18,600	21,700	22,100	8,800	175,900

The following are the principal sources of change in the standardized measure of discounted future net cash flows for subsidiaries:

		$ million
	2008	2007
Sales and transfers of oil and gas produced, net of production costs	(43,600)	(28,300)
Previously estimated development costs incurred during the year	9,400	9,400
Extensions, discoveries and improved recovery, less related costs	4,400	12,300
Net changes in prices and production cost	(146,800)	102,100
Revisions of previous reserves estimates	1,200	(12,200)
Net change in taxation	69,400	(28,300)
Future development costs	(7,400)	(7,800)
Net change in purchase and sales of reserves-in-place	(200)	(700)
Addition of 10% annual discount	14,600	9,100
Total change in the standardized measure during the year of subsidiaries[f]	(99,000)	55,600

[a]The year-end marker prices used were 2008 Brent $36.55/bbl, Henry Hub $5.63/mmBtu and 2007 Brent $96.02/bbl, Henry Hub $7.10/mmBtu.

[b]Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on year-end cost levels and assume continuation of existing economic conditions. Future decommissioning costs are included.

[c]Taxation is computed using appropriate year-end statutory corporate income tax rates.

[d]Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.

[e]Minority interest in BP Trinidad and Tobago LLC amounted to $900 million at 31 December 2008 and $2,300 million at 31 December 2007.

[f]Total change in the standardized measure during the year includes the effect of exchange rate movements.

[g]The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-acccounted investments of those entities.

[h]Minority interest in TNK-BP amounted to $300 million at 31 December 2008 and $1,400 million at 31 December 2007.

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Supplementary information on oil and natural gas (unaudited)

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage.

Crude oil and natural gas production

The following table shows crude oil and natural gas production for the years ended 31 December 2009, 2008 and 2007.

Production for the year[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Crude oil[b]										thousand barrels per day
2009	**168**	**40**	**665**	**8**	**61**	**304**		**123**	**31**	**1,400**
2008	173	43	538	9	66	277		128	29	1,263
2007	201	51	513	8	74	195		228	34	1,304
Natural gas[c]										million cubic feet per day
2009	**618**	**16**	**2,316**	**263**	**2,492**	**621**		**610**	**514**	**7,450**
2008	759	23	2,157	245	2,532	484		696	381	7,277
2007	768	29	2,174	255	2,543	468		609	376	7,222
Equity-accounted entities (BP share)										
Crude oil[b]										thousand barrels per day
2009					**101**		**840**	**194**		**1,135**
2008					92		826	220		1,138
2007					77		832	201		1,110
Natural gas[c]										million cubic feet per day
2009					**392**		**601**	**42**		**1,035**
2008					454		564	39		1,057
2007					429		451	41		921

[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]Crude oil includes natural gas liquids and condensate.

[c]Natural gas production excludes gas consumed in operations.

Productive oil and gas wells and acreage
The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the group and its equity-accounted entities had interests as at 31 December 2009. A gross well or acre is one in which a whole or fractional working interest is owned, while the number of net wells or acres is the s of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves. These tables do not include any information relating to our recent entry into Iraq.

		Europe		North America		South America	Africa	Asia		Australasia	Total
		UK	Rest of Europe	USA	Rest of North America			Russia	Rest of Asia		
Number of productive wells at 31 December 2009											
Oil wells[a]	gross	**282**	**83**	**5,793**	**197**	**3,650**	**668**	**20,593**	**1,657**	**13**	**32,936**
net		**151**	**26**	**2,090**	**76**	**2,045**	**529**	**8,750**	**303**	**2**	**13,972**
Gas wells[b]	gross	**279**		**21,974**	**1,852**	**487**	**104**	**46**	**563**	**68**	**25,373**
net		**133**		**12,359**	**1,236**	**171**	**47**	**23**	**258**	**15**	**14,242**

[a]Includes approximately 3,982 gross (1,750 net) multiple completion wells (more than one formation producing into the same well bore).

[b]Includes approximately 2,834 gross (1,841 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.

	Europe		North America		South America	Africa	Asia		Australasia	Total
				Rest of						

Oil and natural gas acreage at 31 December 2009 — Thousands of acres

		UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Developed	gross	**366**	**65**	**7,587**	**1,186**	**1,740**	**539**	**4,123**	**2,191**	**200**	**17,997**
	net	**201**	**19**	**4,609**	**850**	**470**	**222**	**1,794**	**842**	**39**	**9,046**
Undeveloped[a]	gross	**1,602**	**486**	**7,985**	**6,967**	**7,361**	**105,512**	**10,357**	**15,191**	**4,109**	**159,570**
	net	**919**	**226**	**4,979**	**5,009**	**3,471**	**33,341**	**4,683**	**6,597**	**911**	**60,136**

[a]Undeveloped acreage includes leases and concessions.

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Supplementary information on oil and natural gas (unaudited)

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
2009										
Exploratory										
Productive	**0.1**		**47.2**		**3.0**	**4.5**	**7.0**	**5.3**	**0.6**	**67.7**
Dry	**0.2**		**4.2**			**1.4**	**4.5**	**6.0**	**0.2**	**16.5**
Development										
Productive	**9.3**	**1.5**	**403.8**	**17.9**	**135.4**	**20.8**	**293.0**	**45.8**	**1.6**	**929.1**
Dry			**3.3**			**0.5**	**4.0**	**0.4**	**0.6**	**8.8**
2008										
Exploratory										
Productive	0.8		2.4		4.4	4.3	12.5	0.5	0.6	25.5
Dry		0.5	0.9	0.1	0.4	2.6	23.0	0.5	0.4	28.4
Development										
Productive	6.6	0.5	379.8	28.3	112.5	18.6	10.0	45.4	4.5	606.2
Dry	0.2		1.1	0.9	2.9	1.5	19.5	2.1		28.2
2007										
Exploratory										
Productive	1.6		4.1	0.5		6.1	16.0	1.7	1.1	31.1
Dry			0.7	0.5		1.6	9.0	1.4		13.2
Development										
Productive	0.4	0.8	401.2	36.0	10.0	15.3	246.0	27.5	2.1	739.3
Dry	0.6		4.2	8.8			9.5			23.1

Drilling and production activities in progress

The following table shows the number of exploratory and development oil and natural gas wells in the process of being drilled by the group and its equity-accounted entities as at 31 December 2009. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2009										
Exploratory										
Gross			**112.0**	**4.0**		**5.0**	**8.0**	**3.0**		**132.0**
Net			**30.2**	**1.8**		**2.6**	**4.0**	**2.0**		**40.6**
Development										
Gross	**4.0**	**1.0**	**366.0**	**30.0**	**15.0**	**23.0**	**45.0**	**16.0**		**500.0**
Net	**2.7**	**0.3**	**176.9**	**19.8**	**9.2**	**7.5**	**20.0**	**3.4**		**239.8**

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Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)
/s/D.J. JACKSON
D.J. Jackson
Company Secretary
Dated: 5 March 2010

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