Annual Report and Form 20-F 2012

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Building a stronger, safer BP

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Form 20-F 2012
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Building a stronger,
safer BP

Front cover imagery
The Petroleum Geo-Services (PGS) Ramform Sterling seismic vessel, which conducts seismic surveys for BP.

Left image: the vessel working in the Ceduna Basin, Australia.

Centre image: the vessel tows 12 streamers (pictured) behind it, each 8km long and equipped with hydrophones to pick up echoes from the rocks below the seabed.

Right image: seismic data is picked up by vessel’s onboard computer system.

BP in 2012

The group made good progress this year. We worked to enhance safety and risk management. We continued to meet our commitments in the Gulf of Mexico. We sold assets and reduced complexity. And we focused investment on areas where we see higher margins. Over the following pages, we report on the actions taken to build a stronger, safer BP.

Business review: Group overview Pages 3 – 32
Business review: BP in more depth Pages 33 – 100
Corporate governance Pages 101 – 152
Shareholder information Pages 153 – 160
Additional disclosures Pages 161 – 176
Financial statements Pages 177 – PC11

Information about this report

Cautionary statement
This document should be read in conjunction with the cautionary statement on page 32.

Frequent abbreviations

ADR
American depositary receipt.

ADS
American depositary share.

Barrel (bbl)
159 litres, 42 US gallons.

b/d
Barrels per day.

boe
Barrels of oil equivalent.

GAAP
Generally accepted accounting practice.

Gas
Natural gas.

Hydrocarbons
Crude oil and natural gas.

IFRS
International Financial Reporting Standards.

Liquids
Crude oil, condensate and natural gas liquids.

LNG
Liquefied natural gas.

LPG
Liquefied petroleum gas.

mb/d
Thousand barrels per day.

mboe/d
Thousand barrels of oil equivalent per day.

mmboe
Million barrels of oil equivalent.

mmBtu
Million British thermal units.

MW
Megawatt.

NGLs
Natural gas liquids.

PSA
Production-sharing agreement.

RC
Replacement cost.

SEC
The United States Securities and Exchange Commission.

Tonne
2,204.6 pounds.

Certain definitions
For definitions of certain financial and contractual terms see pages 98-99.

Key performance indicators
Definitions for our group KPIs are provided on pages 28-29.

This document constitutes the Annual Report and Accounts in accordance with UK requirements and the Annual Report on Form 20-F in accordance with the US Securities Exchange Act of 1934, for BP p.l.c. for the year ended 31 December 2012. A cross reference to Form 20-F requirements is on page 20F.

This document contains the Directors' Report, including the Business Review and Management Report, on pages 3-126 and 147-175, and 178. The Directors' Remuneration Report is on pages 127-145. The consolidated financial statements of the group are on pages 177-286 and the corresponding reports of the auditor are on pages 179-181. The parent company financial statements of BP p.l.c. and corresponding auditor's report are on pages PC2-PC11 and page PC1 respectively.

The statement of directors' responsibilities, the independent auditor's report on the annual report and accounts to the members of BP p.l.c. and the parent company financial statements of BP p.l.c. and corresponding auditor's report do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

BP Annual Report and Form 20-F 2012 and *BP Summary Review 2012* may be downloaded from *bp.com/annualreport*. No material on the BP website, other than the items identified as *BP Annual Report and Form 20-F 2012* or *BP Summary Review 2012*, forms any part of those documents.

BP p.l.c. is the parent company of the BP group of companies. The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001. Where we refer to the company, we mean BP p.l.c. Unless otherwise stated, the text does not distinguish between the activities and operations of the parent company and those of its subsidiaries, and 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. 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 on the New York Stock Exchange in the form of ADSs (see page 154 for more details).

The term 'shareholder' in this report means, unless the context otherwise requires, investors in the equity capital of BP p.l.c., both direct and indirect. As BP shares, in the form of ADSs, are listed on the New York Stock Exchange (NYSE), an Annual Report on Form 20-F is filed with the US Securities and Exchange Commission (SEC). Ordinary shares are ordinary fully paid shares in BP p.l.c. of 25 cents each. Preference shares are cumulative first preference shares and cumulative second preference shares in BP p.l.c. of £1 each.

Trade marks of the BP group appear throughout this Annual Report and Form 20-F in italics. They include:

ampm
Aral
ARCO
BP
BP Ultimate
Castrol
Castrol CRB
Castrol EDGE
Castrol Magnatec
Designer Water
Field of the Future
LoSal
Project *20K*
Pushing Reservoir Limits
Veba Combi-Cracking (VCC)

EcoBoost is a trade mark of Ford Motor Company.
SkyMine is a trade mark of Skyonic Corporation.
Permasense is a trade mark of Permasense Limited.

Registered office and our worldwide headquarters:

BP p.l.c.
1 St James's Square
London SW1Y 4PD
UK
Tel +44 (0)20 7496 4000

Our agent in the US:

BP America Inc.
501 Westlake Park Boulevard
Houston, Texas 77079
US
Tel +1 281 366 2000

Registered in England and Wales No. 102498.
Stock exchange symbol 'BP'.

Business review

Group overview

An overview of the key actions, events and results in 2012, together with commentary on BP's performance in the year and our priorities as we move forward.

BP at a glance

Business model
For more information on our business model see pages 15-19.

Who we are

We aim to create value for shareholders by helping to meet growing demand for energy in a responsible way.

Our activities also generate jobs, investment, infrastructure and revenues for governments and local communities. We operate in over 80 countries.

Our priorities are to enhance safety and risk management, earn back trust and grow value. We strive to be a safety leader in our industry, a world-class operator, a responsible corporate citizen and a good employer.

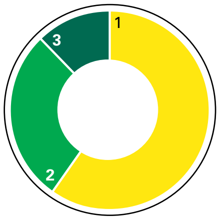
We are working to build a stronger, safer BP that plays to its distinctive strengths and capabilities: exploration, operations in deep water, the managing of giant fields and gas value chains, and our downstream business. Innovative technology and strong relationships with governments, partners and communities around the world underpin our activities.

The key performance indicators (KPIs) for BP are shown on pages 28-29. Some of the financial KPIs are not recognized GAAP measures, but are provided for investors because they are closely tracked by management to evaluate BP's operating performance and to make financial, strategic and operating decisions.

Group

BP p.l.c. is the parent company of the BP group of companies. Our worldwide headquarters is in London.

Employees by business segment



🟨 1. Downstream*	51,300
🟩 2. Upstream	24,000
■ 3. Other businesses and corporate and Gulf Coast Restoration Organization	10,400
Total	**85,700**

*Including service station staff.

$22.5 bn...

$11.6 bn
profit attributable to BP shareholders

$20.4 bn
operating cash flow

18.7%
gearing (net debt ratio)[a]

19%
reduction in loss of primary containment

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[a] Net debt is not a recognized GAAP measure, see Financial statements Note 35.

See KPIs pages 28-29.

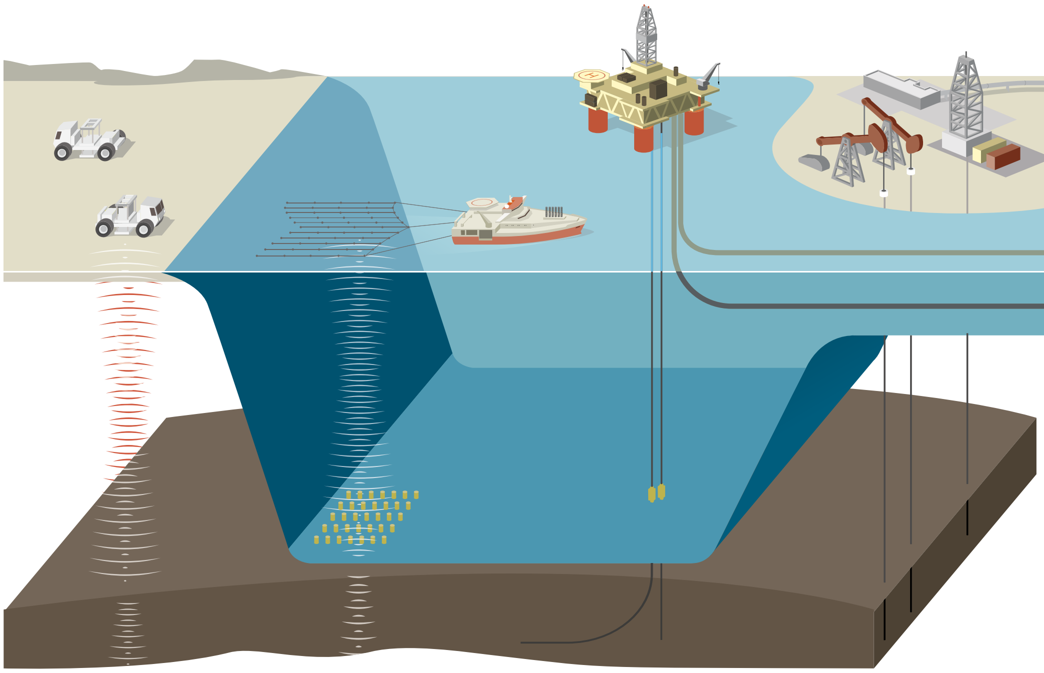
Our business model

Finding
oil and gas

First, we acquire exploration rights, then we search for hydrocarbons beneath the earth's surface.

Developing and extracting
oil and gas

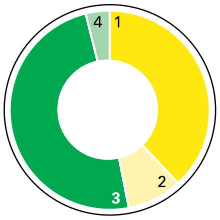
Once we have found hydrocarbons, we work to bring them to the surface.



Upstream

Our Upstream segment manages its exploration, development and production activities through global functions with specialist areas of expertise.

Proved reserves[b]



Liquids[c]	
🟨 1. Subsidiaries	4,477
🟨 2. Equity-accounted entities	1,033
Total	**5,510**

Natural gas	
🟩 3. Subsidiaries	5,736
🟩 4. Equity-accounted entities	439
Total	**6,175**

$22.5 bn
replacement cost profit before interest and tax

67,900km²
new exploration access

28
countries of operation

5
major project start-ups

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[b] Million barrels of oil equivalent. Natural gas is converted to oil equivalent at 5.8 billion cubic feet (bcf) = 1 million barrels.
[c] Liquids comprise crude oil, condensate, natural gas liquids and bitumen.

See Upstream pages 63-71.

All data provided on pages 4 and 5 is as at, or for the year ended, 31 December 2012.

Transporting and trading
oil and gas

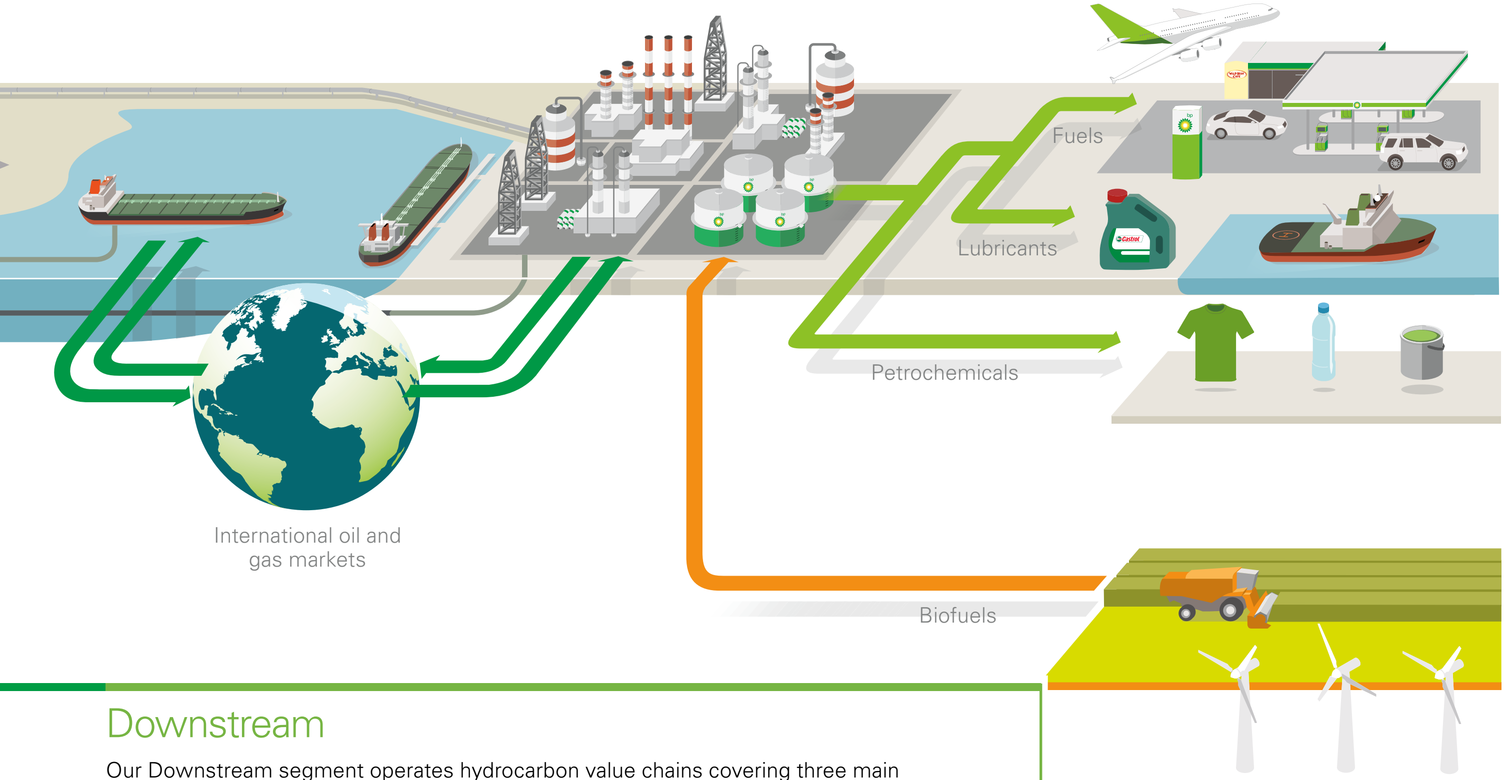
We move hydrocarbons using pipelines, ships, trucks and trains and capture value across the supply chain.

Manufacturing
fuels and products

We refine, process and blend hydrocarbons to make fuels, lubricants and petrochemicals.

Marketing
fuels and products

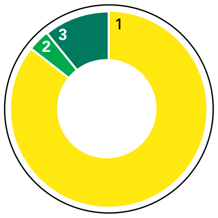
We supply our customers with fuel for transportation, energy for heat and light, lubricants to keep engines moving and the petrochemicals required to make a variety of everyday items.



Downstream

Our Downstream segment operates hydrocarbon value chains covering three main businesses – fuels, lubricants and petrochemicals.

Operating capital employed[d]



🟨 1. Fuels	$42.7bn
🟩 2. Lubricants	$1.9bn
🟩 3. Petrochemicals	$5.3bn

$2.8 bn
replacement cost profit before interest and tax

14.7 million tonnes
of petrochemicals produced in the year

2.4 million barrels
of oil refined per day

39%
of our lubricants sales were premium grades

Investing
in renewable energy

We develop and invest in biofuels and wind. BP's lower-carbon businesses and investments in future options are operated through our Alternative Energy business.

7.2 million tonnes
biofuels – total sugar cane crush capacity per annum

1,558MW[e]
net wind generation capacity

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

[e] Excludes 32MW of capacity in the Netherlands, which is managed by our Downstream segment.

See Downstream pages 72-79.

See Alternative Energy pages 82-83.

Where we operate

BP is active in over 80 countries. This map shows our key operating sites across the world.

● The shaded areas indicate countries where we have operations.

Upstream[a]

- ◉ Primarily (>75%) liquids.
- ▲ Primarily (>75%) natural gas.
- ★ Liquids and natural gas.
- ☆ Exploration site.

[a] Locations are categorized as liquids or natural gas based on 2012 production. Where production is yet to commence materially, categorization is based on proved reserves. Exploration sites have no significant proved reserves or production as at 31 December 2012.

Upstream see pages 63-71.

Downstream

- ▣ BP refinery.
- ▼ Petrochemicals site(s).
- ☒ Asset held for sale.

Downstream see pages 72-79.

Alternative Energy

- ▣ Operational assets.
- ★ Technology assets.

We have interests in 16 wind farms in the US, and operate four ethanol production facilities – three in Brazil and one in the UK.

Alternative Energy see pages 82-83.

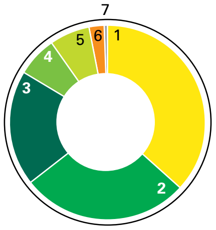
TNK-BP

- △ TNK-BP upstream assets (wholly or partly owned by TNK-BP).
- ▽ TNK-BP refineries (wholly or partly owned by TNK-BP).

BP's investment in TNK-BP is classified as an asset held for sale in the group balance sheet at 31 December 2012.

TNK-BP see pages 80-81.

BP group headcount by region
(including 14,700 service station staff)



🟨 1. Europe	31,600
🟩 2. US and Canada	23,800
🟩 3. Asia	16,400
🟩 4. South and Central America	5,800
🟩 5. Middle East, North Africa	5,500
🟧 6. Sub-Saharan Africa	2,300
⬜ 7. Russia	300

Alaska

We opened our Alaska office in 1959 and acquired our first federal licences that year. We now operate 13 oilfields and four pipelines. We also own a significant interest in six other producing fields.

Fuels

The fuels business is made up of seven regionally based fuels value chains (FVCs), a number of regionally focused fuels marketing businesses, a global aviation fuels marketing business that markets products in more than 45 countries and the global oil supply and trading activities. These businesses sell refined petroleum products including gasoline, diesel, aviation fuel and LPG.

Fuels value chains

US: North West, South West, East of Rockies.

Europe: Rhine, Iberia.

Rest of world: Australia and New Zealand, Southern Africa.

Gulf of Mexico

We are one of the largest lease holders and producers of oil and gas in the region's deep water. In 2011 we resumed drilling in the region. We now produce oil and gas from four operated hubs and three non-operated hubs.

Trinidad & Tobago

BP has been exploring in Trinidad since 1939. Today we hold exploration and production licences covering more than 1,800,000 acres. We operate 13 offshore platforms and an onshore processing facility.

North Sea region

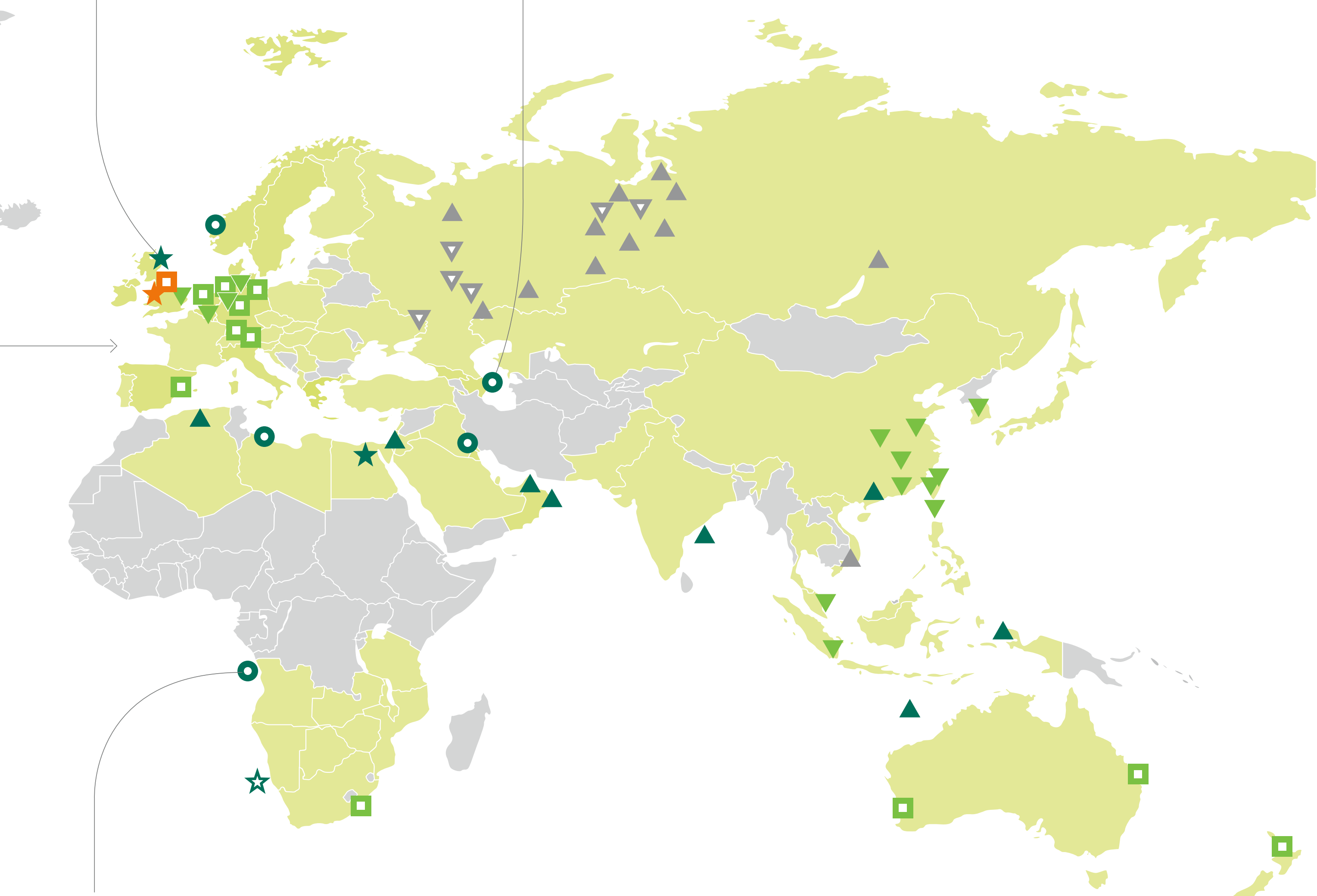
BP was the first company to find hydrocarbons in the North Sea region, in 1965. We now have one of the largest asset bases in the region, operating around 30 oil and gas fields, two major terminals and an extensive network of pipelines.

Azerbaijan

Our major projects include the Azeri-Chirag-Gunashli oil field; the Shah Deniz gas field; three major terminals; and a number of long-distance pipelines, including the 1,768km Baku-Tbilisi-Ceyhan pipeline, which carries oil across Azerbaijan, Georgia and Turkey.

Lubricants

Our lubricants business manufactures and markets lubricants and related products and services. It is a global business marketing products in more than 70 countries leveraging brand, technology and relationships. We focus our resources on core and growth markets such as Brazil, Russia, India and China.



Angola

We have been involved in Angola since the 1970s. We now hold a position in nine major deepwater licences, along with equity in the Angola LNG project. We achieved two major project start-ups in 2012.

Petrochemicals

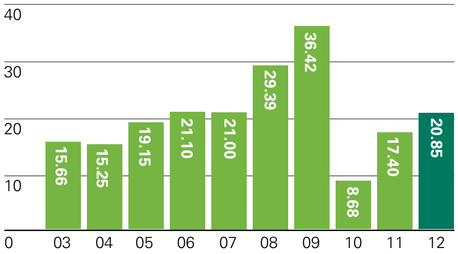
Our petrochemicals business produces petrochemicals products at manufacturing units around the world that, for the most part, use proprietary BP technology. At the end of the year the business comprised 15 manufacturing sites with approximately 40% of our capacity in Asia, and 30% in each of Europe and the US. We sell our products to customers in more than 40 countries.

Chairman's letter

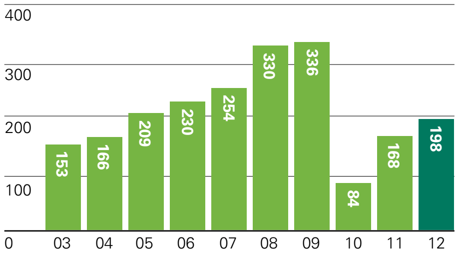
> Our plans, priorities and directions are clear. I see great opportunities ahead.
>
> **Carl-Henric Svanberg**

10-year dividend history

UK (pence per ordinary share)



US (cents per ADS)



1 ADS represents six 25 cent ordinary shares.

Dear fellow shareholder

In 2012 the board had three priorities. First, to address uncertainty from ongoing litigation in the US and our partnership in Russia. Second, to reinforce the strategic direction of the group. Third, to accelerate the company's momentum and build confidence. All of these were pursued in the context of the board's active monitoring of safety and risk management.

Substantial progress has been made in meeting these priorities. This progress gave the board confidence to raise the quarterly dividend by 14% in February 2012 and by 12.5% in October. The increased dividend represents an important milestone on the road to improved shareholder value. We are maintaining a progressive dividend policy, increasing returns to you, in line with financial performance and outlook.

The pursuit of energy will always involve risk, so it is essential that safety remains front of mind. From safe and reliable operations comes trust, and we need that trust if BP is to create value for you and to help meet the world's energy needs.

Looking ahead, your board sees strong prospects for BP in a world that requires a growing supply of energy. We are aware that we still have some way to go. We continue to face a number of uncertainties in the US, for example. The board thanks you for your continued patience and support as we work to address these issues.

In working to resolve uncertainty, two matters demanded the close attention of your board.

In the US, the company has faced legal proceedings related to the Deepwater Horizon accident. Our settlements with the US government, the Securities and Exchange Commission and others were each important steps forward in reducing uncertainty.

In Russia, the agreed sale of our 50% shareholding in TNK-BP to Rosneft, and the settlement with our partners, have brought clarity. The disposal agreement will provide us with an increased stake in Rosneft, such that on completion, BP will have a 19.75% share of the biggest publicly traded oil company in the world in terms of oil production and reserves. In due course BP expects to have two seats on its nine-person board. BP has worked with Rosneft for some 15 years. Our joint ambition is that BP's people, processes and technologies will help to significantly enhance Rosneft's value over time, as they did at TNK-BP.

During the year the board supported Bob Dudley, our group chief executive, on the implementation of the 10-point plan and the further implementation of the functional organization. We worked with him to develop the group strategy beyond 2014. Bob, the executive team and all our employees have made a huge contribution, working to reach our milestones and secure a promising future for the company during a tough period. Bob has shown steady and determined leadership through this time. I thank him and everyone at BP for their hard work.

The qualities of BP's employees were once again demonstrated in January 2013, following the violent attack at In Amenas in Algeria. This shocking event deeply affected us all, but across the company people responded with great resilience. We will always remember those who lost their lives in this terrible incident.

Board performance
For information about the board and its committees see pages 101-126.

Our strategy
For more on our strategic priorities and longer-term objectives see pages 20-21.

As 2012 progressed the board saw the company start to move forward with greater confidence. It is important that this momentum continues.

Our board committees have provided effective oversight of the company and its operations, which has enabled the board to focus on its three priorities. Outside the boardroom, our non-executive directors have continued to pay visits to key parts of the business. My own visits this year included Angola, Azerbaijan, the North Sea, Japan and the US.

The board has seen substantial change. For this reason, we have asked Antony Burgmans to serve for a further three years. I am pleased that we will continue to benefit from his experience and understanding of the company. Byron Grote is retiring after 33 years with BP, including more than 12 years on the board. I thank him for his dedication and the exceptional contribution he has made to this company. As we move through 2013, the board is well balanced, with deep experience in our industry and a broad range of skills across business and finance.

We will refresh the board as and when required. I believe board diversity – including the representation of women at the top – helps to make boards more effective. We will continue to work to identify candidates from a range of backgrounds who can make a unique and powerful contribution to BP.

One of the vital tasks of the board is to ensure strategy is matched to the world we see ahead. Energy remains the engine of progress, and we expect rising populations and increasing industrialization to generate strong demand to 2030 and beyond. The world will continue to be dependent on fossil fuels in the medium term. Along with providing the hydrocarbons needed, we are also involved in developing the resources, technologies and policies required over the long term.

Our industry keeps evolving. In the past international oil companies dominated access to resources. Then national oil companies took control of the greater share. But much of the easiest-to-reach oil has been developed. So we are now entering a third era, where co-operation between partners is the key to unlocking the resources found in the most challenging locations. For BP, advantage now comes from exceptional capability rather than exceptional scale. Our future is about high-margin, high-quality production, not simply volume.

Oil will continue to be BP's prime focus, and we aim to extend our extraordinary track record in finding and developing new resources. We will keep making selective investments in natural gas, with an emphasis on assets that generate good margins. And we will be selective in the Downstream too, choosing to operate where our refining and marketing assets are connected to attractive markets.

Over the past three years BP has had to change. Through our reorganization, we are a simpler company. Through our asset sales, we are stronger financially. Through our actions, we have reduced complexity and risk. Our plans, priorities and direction are clear. I see great opportunities ahead, as we continue to build a stronger, safer BP that meets the expectations of our shareholders and the wider world.

Carl-Henric Svanberg
Chairman
6 March 2013

Carl-Henric Svanberg at the Sangachal terminal control room during his three-day trip to Azerbaijan (top); Professor Dame Ann Dowling on the Thunder Horse platform in the Gulf of Mexico (middle); Brendan Nelson and Phuthuma Nhleko at BP's North America Gas operations in east Texas, US (bottom).

Group chief executive's letter

> We are building a platform for growth that should serve us well for many years to come.
>
> **Bob Dudley**

Dear fellow shareholder

BP made important progress in 2012. We achieved a series of strategic milestones and remained on course with our plans to 2014 and beyond. We made great strides forward in Russia and the US. We continued to enhance risk management. We focused on our areas of greatest strength. And we sold assets to capture value, simplify the business and reduce risk.

Before I say more about our activities and plans, I would like to reflect, with great sadness, on the terrible events that took place at the In Amenas joint venture facility in Algeria in January 2013. Our thoughts are with the families and friends of those who lost their lives in the attack. We are working with government agencies and others to determine what can be learned from this shocking incident.

Coming back to our work over the past few years, people may not be fully aware of the enormous scale of the change we have made. By the end of 2012 we had announced asset sales of $38 billion, essentially reaching our target a year early. Since the divestment programme began, we have sold around half our upstream installations and pipelines, and one-third of our wells – while retaining roughly 90% of our proved reserves base and production. Meanwhile, we are gaining new exploration access, rolling out high value projects and upgrading assets.

Our Downstream segment has had an excellent year with strong operational performance and record underlying profits.[a] We made good progress on the modernization programme of our Whiting refinery and reached agreement on the divestment of two major refineries in the US, completing the sale of our Texas City refinery in February 2013.

There is more to do and there will always be new challenges to face, but we are steadily acting to build a stronger, safer BP.

We are addressing uncertainty in the US

In 2012 we resolved federal criminal charges with the Department of Justice and securities claims with the SEC. We continue to work with the Environmental Protection Agency to resolve suspension and debarment issues.

We have consistently said we are willing to settle all outstanding claims on reasonable terms, but we are also prepared to defend the company and its actions in court. We will do what is in the best interests of our shareholders. I recognize that ongoing proceedings prolong uncertainty, so we will endeavour to update you as events unfold.

Back in 2010 we said that we would help restore the environment and economy of the Gulf. We are holding true to that promise. In 2012 we made our final payment into the $20-billion Trust fund, from which $9.5 billion has been distributed to date. We supported environmental research and provided funds for the local tourism industry. Having grown up in the Gulf, I am heartened that the tourists are back, beaches are busy and the fishing is good. To date, BP has made total payments directly related to the accident and oil spill of $32.8 billion. We will continue to meet our commitments in the region.

We are repositioning BP in Russia

In 2012 we agreed to sell our 50% shareholding in TNK-BP to Rosneft. TNK-BP proved to be an outstanding investment, generating substantial value for BP. From an initial commitment of around $8 billion, it has returned some $19 billion of dividends to us. But the time had come to move on.

Carl-Henric Svanberg and Bob Dudley with Igor Sechin, President of Rosneft, on the day the BP board approved the transaction.

$19 billion

Dividends received by BP from TNK-BP since 2003.

The new agreement will provide us with an 18.5% share in Rosneft and $12.3 billion of cash, including a dividend of $0.7 billion received from TNK-BP in December 2012. Combined with our existing 1.25% shareholding, we will own 19.75% of Rosneft. We expect the transaction to be completed in the first half of 2013. Through it, we will maintain a strong position in the world's largest oil and gas producing country. And we will be a major investor in a company transforming its asset base, management processes and corporate governance.

We will use our experience in large acquisitions and mergers to support Rosneft as it assimilates TNK-BP's assets. We can also contribute technical skills in areas from exploration and enhanced oil recovery to integrating downstream businesses and international developments. We have confidence in the Russian business environment and we look forward to playing a valued role in the country's future.

We are enhancing safety and risk management

Our employees have been working systematically to enhance safety and risk management. We have changed how we are organized, bringing greater clarity and consistency across the company. In the Gulf of Mexico and elsewhere, we are holding our operations to standards that in many cases go beyond regulatory requirements. And we have turned lessons learned from the 2010 accident into new oil spill response plans and technologies, which we are adopting within BP and sharing with others. I take encouragement from our 19% reduction in loss of primary containment this past year, continuing a multi-year trend.

2012 saw the appointment of Carl Sandlin, who will oversee the implementation of the recommendations of the Bly Report, BP's internal accident investigation. In addition, following our agreement with the US government to resolve all federal criminal claims, we have agreed to take additional actions designed to further enhance the safety of drilling operations in the Gulf. Two independent monitors will be appointed to review and provide recommendations, one regarding process safety for deepwater drilling in the Gulf and the other BP's code of conduct. An independent auditor will review and report on BP's implementation of key terms of the agreement.

We are building a distinctive platform for growth

In shaping our portfolio, we are prioritizing shareholder value. Scale remains important, but we are focused on driving forward our financial performance rather than simply growing production volumes. Operating cash flow and replacement cost profit will take precedence over barrels of production. We are increasing investment in the areas with the greatest potential to generate strong and reliable growth in operating cash flow, from exploration and deepwater operations to giant fields and gas value chains. In the Downstream, we have a portfolio of world-class businesses that are positioned to deliver material and growing free cash flows.[b]

There is plenty for us to explore. During the year we gained new access in six countries. Since 2010 we have accessed around 400,000 square kilometres of new acreage. That is roughly the size of California and more than double the exploration acreage gained from 2000 to 2009.

We continue to have an important presence in many of the world's largest economies and in fast-developing countries too. BP's global footprint and prudent financial approach are important given the potential for turbulence in the world, including further economic and political upheaval. We are well placed to respond to unsettled conditions if and when they appear.

Looking ahead

While facing uncertainties and navigating through testing times, BP emerged from 2012 a somewhat smaller, but stronger company. As we move forward, you will see us keep working to focus, standardize and improve what we do and how we do it. We are building a platform for growth that should serve us well for many years to come.

I want to end by paying tribute to everyone here at BP. This has been another truly demanding year, and our employees have dedicated themselves to their jobs in a way that I find humbling. I am proud of the talent and the terrific spirit of determination to improve that is found within BP. Over the next 12 months and beyond, we will continue our work to enhance safety, earn back trust and create value.

Bob Dudley

Bob Dudley
Group Chief Executive
6 March 2013

The new US-based High-Performance Computing centre, which is currently under construction, will enable BP scientists to complete an imaging project in one day – whereas it would have taken four years nearly a decade ago.

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[a] Downstream underlying profit is not a recognized GAAP measure. See page 27 for the equivalent measure on an IFRS basis, which is replacement cost profit before interest and tax. See Certain definitions on page 98 for further information on underlying profit.

[b] See footnote e on page 21 for a definition of free cash flow.

Energy outlook

Looking ahead, we expect demand for energy to grow and the challenges facing our industry to be met by a diverse mix of fuels and technologies.

Our market in 2012

World economic growth was weak in 2012 – below its historic trend – and we expect subdued global growth to continue in 2013. Emerging economies with stronger productivity and rising populations, led by China and India, are set to drive growth. Developed countries may lag as they continue to address internal fiscal imbalances.

Global demand for energy, including oil, continued to expand modestly in 2012, with a weak economy and high oil prices weighing on demand.

As a result, the growth in world oil consumption remained weak in 2012, with continued growth in China and other non-OECD countries offsetting yet another decline in OECD countries. With oil markets balancing lower production from certain countries against weak consumption and high OPEC production, average crude oil prices in 2012 were similar to the previous year, averaging $111.67 per barrel.

Natural gas prices continued to diverge globally in 2012, with lower prices in the US and increases in Europe and the Far East.

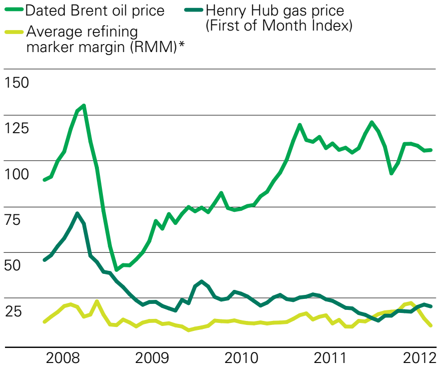
Crude prices
For more information on crude oil and natural gas prices see page 64.

Globally, refining margins improved on average as refinery closures and operational issues reduced product supply. Demand continues to grow in non-OECD countries but the weak financial environment in OECD countries has seen demand growth weaken.

Refining margins
For more information on the BP refining marker margin and other measures see page 73.

Concerns about the volatility of commodity and financial markets, energy security and climate change have led to continued debate over the appropriate role of markets, government regulation and other policy measures that affect the supply and consumption of energy. Given the pressures in the sector, we expect regulation and taxation of the energy industry and energy users to increase in many areas in the future.

Crude oil and gas prices, and refining margins ($ per barrel of oil equivalent)

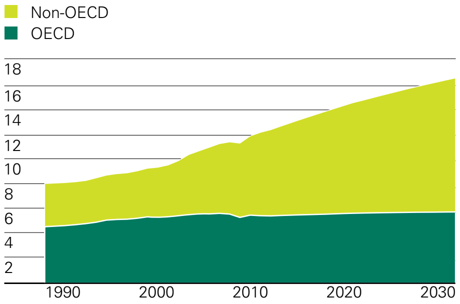


Source: Platts/BP.
*See Downstream on page 73 for further information on RMM.

The facts and figures used in this section are derived from *BP Energy Outlook 2030*, published in January 2013, unless otherwise indicated, and represent a 'base case' or most likely projection.

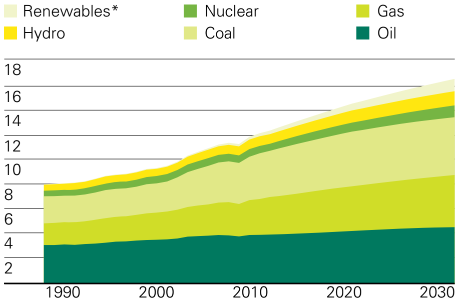
For more information see *bp.com/energyoutlook*

Energy consumption by region
(billion tonnes of oil equivalent)



Source: *BP Energy Outlook 2030.*

Energy consumption by fuel
(billion tonnes of oil equivalent)



*Includes biofuels.
Source: *BP Energy Outlook 2030.*

1.6% per annum

Projected world primary energy consumption growth to 2030.

Longer-term outlook

Challenges and opportunities

The world's population is projected to increase by 1.3 billion from 2011 to 2030, with real income likely to double over the same period. These factors will lead to increased energy demand and consumption. Energy and climate policies, efficiency gains and a long-term structural shift in fast-growing economies away from industry and towards less energy-intensive activities will help to restrain any increase, but the overall trend is likely to be one of strong growth. We expect demand for energy to increase by as much as 36% between 2011 and 2030, with nearly 93% of the growth to occur in non-OECD countries.

We estimate that there are enough energy resources available to meet the increases in demand in the foreseeable future, but there will be challenges as well as opportunities.

Energy security represents a challenge. More than 60% of the world's natural gas is concentrated in just four countries. More than 80% of global oil reserves are located in nine countries, most of which are well away from the hubs of energy consumption.

Meeting growing demand for secure and sustainable energy will also present an affordability challenge as the availability of easily accessible fossil fuels slowly diminishes, with many lower-carbon resources and technologies remaining costly to produce at scale.

While energy is available to meet growing demand, action is needed to limit carbon dioxide (CO_2) and other greenhouse gases being emitted through fossil fuel use. Burning fossil fuels can also raise local and regional air quality issues.

Meeting the energy challenge

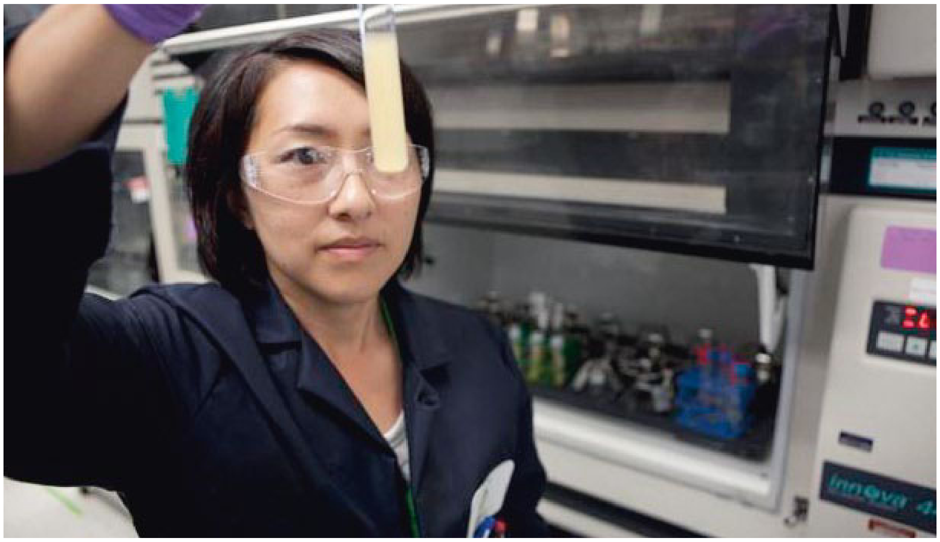
We believe that, increasingly, the global energy challenge can only be met through a diverse mix of fuels and technologies. A broad mix can enhance national and global energy security while supporting the transition to a lower-carbon economy. This is one reason why BP's portfolio includes oil sands, shale gas, deepwater oil and natural gas production, biofuels and wind.

We estimate that today's oil reserves could meet more than 45 years of demand at current consumption rates, while known supplies of natural gas could meet demand for nearly 60 years and coal could meet demand for up to 120 years.[a]

Our industry has a track record in expanding the availability of resources through investment and the application of technology. For example, in 1981 the world's oil reserves stood at an estimated 700 billion barrels. By 2011 this had risen to 1,650 billion barrels, even though 800 billion barrels had been consumed in the intervening three decades.

Oil and natural gas

We believe oil and natural gas are likely to represent about 53% of total energy consumption in 2030. Even under the International Energy Agency's (IEA) most ambitious climate policy scenario (the 450 scenario), oil and gas would still make up 50% of the energy mix in 2030, with combined demand projected to exceed current levels in absolute terms.[b] The 450 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.



In the US, our biofuels business is focusing on the development of cellulosic ethanol technology at facilities in San Diego, California (right) and Jennings, Louisiana.

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[a] *BP Statistical Review of World Energy June 2012.* These reserve estimates are compiled from official sources and other third-party data, which may not be based on proved reserves as defined by SEC rules.

[b] From *World Energy Outlook 2012©*, OECD/IEA 2012, page 553.

Science not sentiment

A BP-funded consortium of experts from leading universities around the world is examining the complex relationships between natural resources and the supply and use of energy. The aim of this multidisciplinary research programme – the Energy Sustainability Challenge (ESC) – is to provide scientific evidence to underpin effective policy making and business planning.

The ESC is concentrating on the nexus of land, water, minerals and energy. It is hoped this work will help the world to develop sustainable energy pathways founded on science rather than sentiment. We anticipate it will provide BP with greater clarity on how sustainability should inform our planning, investments and operations.

bp.com/energysustainabilitychallenge

93%

Non-OECD countries' share of energy consumption growth to 2030.

+45%

Net growth in unconventional global energy production from 2020 to 2030.

New sources of hydrocarbons are more difficult to reach, extract and process. This will require BP and others in our industry to develop new technologies to boost recovery from declining fields and commercialize currently inaccessible resources. Greater energy intensity could be required to extract these resources, which means operating costs and greenhouse gas emissions from operations are likely to increase.

Renewables

Renewable energy is the fastest growing fuel and is projected to grow by 7.6% per annum to 2030. Renewable energies are starting from a low base however, and we project that they are only likely to meet around 6% of total energy demand by 2030. With a few exceptions, renewables are not yet competitive with conventional power and transportation fuels. Sufficient policy support is required to help commercialize effective lower-carbon options and technologies, but renewables will ultimately need to become free from subsidy and commercially self-sustaining.

Energy efficiency and innovation

While overall energy consumption is set to increase, economic growth is expected to become significantly less energy intensive, especially in non-OECD economies. In fact, globally, demand for energy is expected to rise at less than half the rate of gross domestic product (GDP). The amount of energy required to generate $1 million in China has already dropped from 350 tonnes of oil equivalent in 1980 to 200 tonnes of oil equivalent or less today.

Innovation can play a key role in improving technology design, process and use of materials, bringing down cost and increasing efficiency. In transport, for example, we believe that efficient combustion engines and power train technologies could offer the quickest and most effective pathway to a secure, lower-carbon future.

Policy, prices and access

If the world's growing demand for energy is to be met in a sustainable way, we believe that governments must set a stable and enduring framework for the private sector to invest and for consumers to choose wisely. As part of this, governments will need to provide secure access for exploration and development of energy resources; define mutual benefits for resource owners and development partners; and establish and maintain an appropriate legal and regulatory environment.

We believe open and competitive markets are the most effective way to encourage companies to find, produce and distribute diverse forms of energy sustainably. The US experience with shale gas shows how an open and competitive environment can drive technological innovation and unlock resources. We also believe that putting a price on carbon – one that treats all carbon equally, whether it comes out of an industrial smokestack or a car exhaust – will make energy efficiency and conservation more attractive to businesses and individuals, and lower-carbon energy sources more cost competitive.

Beyond 2030

We expect that growing population and per capita incomes will continue to drive growing demand for energy. These dynamics will be shaped by future technology developments, changes in tastes, and future policy choices – all of which are inherently uncertain. Concerns about energy security, affordability and environmental impacts are all likely to be important considerations. These factors may accelerate the trend towards more diverse sources of energy supply, a lower average carbon footprint, increased efficiency and demand management.

BP is sensitive to the challenges and opportunities outlined here. We actively monitor developments and continually assess a range of potential outcomes and their implications for our strategy.

Our business model

Through our business model we aim to create value across the hydrocarbon value chain. This starts with exploration and ends with the supply of energy and other products fundamental to everyday life.

BP is the largest foreign investor in Azerbaijan and operates two production-sharing agreements – Azeri-Chirag-Gunashli and Shah Deniz – and other exploration leases. Above is the West Azeri platform.

Who we are

BP is one of the world's leading integrated oil and gas companies.[a] We aim to create value for shareholders by helping to meet growing demand for energy in a responsible way. We strive to be a safety leader in our industry, a world-class operator, a responsible corporate citizen and a good employer.

Through our work we provide customers with fuel for transportation, energy for heat and light, lubricants to keep engines moving, and the petrochemicals products used to make everyday items as diverse as paints, clothes and packaging. Our projects and operations help to generate employment, investment and tax revenues in countries and communities around the world.

At each stage of the hydrocarbon value chain there are opportunities for us to create value – both through the successful execution of activities that are core to our industry, and through the application of our own distinctive strengths and capabilities in performing those activities.

How we are organized

We have two main business segments: Upstream and Downstream. Through these we find, develop and produce essential sources of energy, and turn these sources into products that people need.

We also hold a 50% shareholding in the major Russian oil company TNK-BP, which owns upstream and downstream assets. In November, marking what we expect to be an exciting new future for BP in Russia, we signed final, binding agreements with Rosneft, Russia's leading oil company, for the sale of our share in TNK-BP for $12.3 billion in cash (which includes a dividend of $0.7 billion received from TNK-BP in December 2012) and an 18.5% stake in Rosneft. The transaction is expected to complete in the first half of 2013. Combined with BP's existing 1.25% shareholding, this will result in BP owning 19.75% of Rosneft.

In renewable energy, our investments and activities are focused on biofuels and wind. In addition, our emerging businesses and ventures unit invests in a broad range of energy projects and technologies. Our renewables and venturing activities are managed through our Alternative Energy business, which is reported in Other businesses and corporate on page 82.

Our commitments

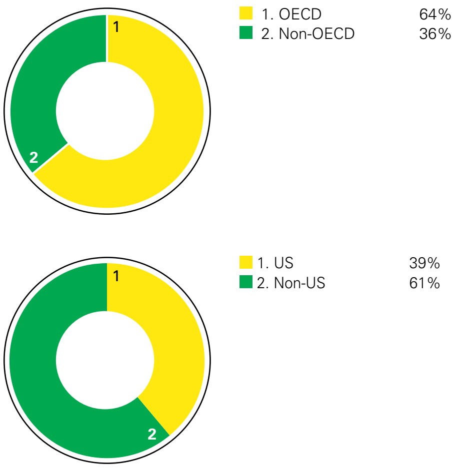
Keeping a relentless focus on safety is the top priority for everyone at BP.

Rigorous management of risk helps to protect the people at the front line, the places in which we operate and the value we create. We understand that operating in politically complex regions and technically demanding geographies requires particular sensitivity to local environments.

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

Our business model – continued

Location of group's fixed assets



Our employees
For more on BP's employees in 2012 see pages 55-56.

The relationships we form with shareholders, governments, regulators, non-governmental organizations, local communities, customers, franchisees, partners, contractors, suppliers and others in our industry are crucial to the success of our business. We are committed to building long-lasting relationships, meeting our obligations and acting responsibly.

We believe that the best way to achieve sustainable success as a group is to act in the long-term interests of our shareholders, our partners and society. Through our work we aim to create value for our investors and benefits for the communities and societies in which we operate, with the safe and responsible supply of energy playing a vital role in economic development.

Our people

We employ nearly 86,000 people, including 14,700 service station staff in Europe and Asia. The majority of our employees are located in the US and Europe. The qualities and abilities of our employees have a powerful effect on our ability to compete and meet our commitments to investors and the wider world. We provide a range of professional development programmes and training to help our employees develop their skills and capabilities. We are committed to creating an inclusive work environment where everyone is treated fairly, with dignity, respect and without discrimination.

Our presence

As a global group, our interests and activities are held or operated through subsidiaries, branches, joint ventures or associates established in – and subject to the laws and regulations of – many different jurisdictions. Our 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. BP has freehold and leasehold interests in real estate in numerous countries, but no individual property is significant to the group as a whole. For more on the significant subsidiaries of the group at 31 December 2012 and the group percentage of ordinary share capital see Note 45 on page 255. For information on significant jointly controlled entities and associates of the group, see Notes 24 and 25 on pages 218-220.

Value creation

We seek to add value at each stage of our operations, from exploration to marketing. We believe that by operating across the full hydrocarbon value chain we can create more value for shareholders, as benefits and costs can often be shared by our segments. Integration also enables us to develop shared functional excellence in areas such as safety and operational risk, environmental and social practices, procurement, technology and treasury management more efficiently.

Material improvement

Purified terephthalic acid (PTA) is the primary raw material for polyester, which is used in textiles and packaging. Our proprietary PTA technology has significantly lower capital and operating costs compared with conventional PTA plants. Our estimates suggest that it discharges 75% less water, generates 65% lower greenhouse gas emissions and 95% lower solids waste compared with competing technologies.

We have invested significantly in this proprietary technology and believe that maximum value for BP will come from both investing in projects such as our Zhuhai 3 project in Guangdong, China and through licensing. We announced our first third-party, non-affiliate, PTA licensing deal in July to JBF Petrochemicals. They intend to build a 1.25 million tonnes per annum PTA unit in India – expected onstream at the end of 2014.

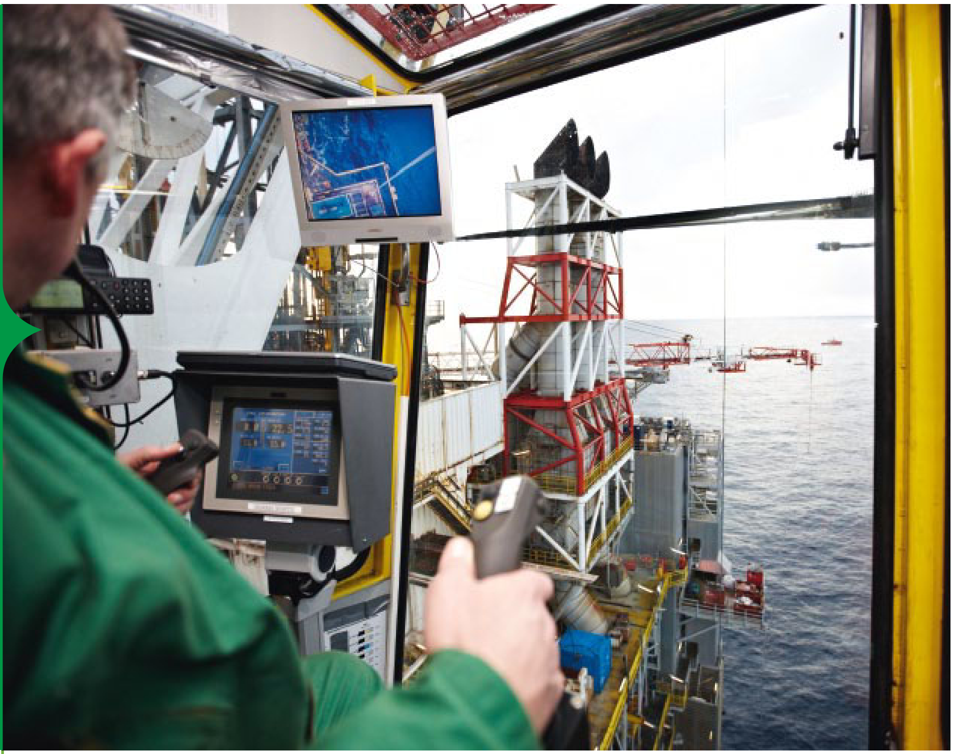
Our work with PTA is part of an ongoing research and development programme designed to improve the manufacturing efficiency in petrochemicals. Along with PTA, we have industry leading technology, intellectual property and know-how in paraxylene and acetic acid.

Salt reduction promises healthy returns

Typically, less than 35% of the oil in a field is extracted, even when wells are flooded with water to increase recovery. That means important resources are currently left untapped, all over the world.

The *LoSal* flooding process is set to significantly improve recovery rates. Developed at BP's UK research centre, the *LoSal* flooding process uses water with a low salt content, which releases more molecules of oil from the sandstone rock in which they are held.

Following a successful trial in the Endicott field in Alaska, we are applying *LoSal* where appropriate in our portfolio. In 2012 Clair Ridge in the North Sea became the first large-scale offshore scheme to deploy the technology. BP estimates that this breakthrough technology (part of BP's suite of *Designer Water* enhanced oil recovery technologies) will increase production by around 42 million barrels of additional oil, compared with conventional water flooding methods.



We aim to protect value by maintaining a rigorous focus on safety, reliability and efficiency across our range of activities. We often work with partners to mitigate risk or gain from complementary skills.

Finding oil and gas
First, we acquire the rights to explore for oil and gas. Through new access we are able to renew our portfolio, discover new resources and replenish our development options.

Developing and extracting oil and gas
When we are successful in finding hydrocarbon resources, we create value by seeking to progress them into proved reserves or by selling them on if they do not fit with our strategic objectives.

If we believe developing and producing the reserves will be advantageous for BP, we will produce the oil and gas, then sell it to the market or distribute it to our downstream facilities.

Transporting and trading oil and gas
We move oil and gas through pipelines and by ship, truck and rail. We use our trading and supply skills and knowledge to find the best routes to deliver supplies to the most attractive markets.

Manufacturing and marketing fuels and products
Using our technology and expertise, we manufacture fuels and products, creating value by seeking to operate a high-quality portfolio of well-located assets safely, reliably and efficiently. We market our products to consumers and other end-users and add value through the strength of our brands.

Our distinctive strengths and capabilities

We consider our areas of distinctive strength to include:

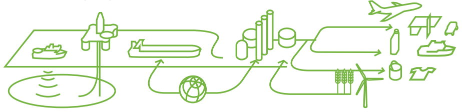
- **Exploration** – acquiring access and searching for hydrocarbons.
- **Deep water** – we have a long track record in finding, developing and producing hydrocarbons in deep water.
- **Giant fields** – managing the scale and complexity of fields with resources believed to exceed 500 million boe.[a]
- **Gas value chains** – seeking to add value as gas moves from field to customer.
- **Downstream** – the pursuit of safe, reliable and efficient operations, and leading returns, across fuels, lubricants and petrochemicals.

These are underpinned by our development and application of technology and our ability to build strong relationships. In addition, we have a long-established integrated supply and trading function.

Strong relationships
We are seeing an evolution in our industry, with international oil companies such as BP establishing new kinds of partnerships and co-operation with governments, national oil companies and other resource holders. The benefits of our value-creating activity are shared with governments and other partners.

We seek opportunities to develop and deploy distinctive capabilities that complement those of our partners. We also partner with universities and governments in pursuit of improving the technologies available to us, so we can enhance our operations and develop new products. We aim to support and improve standards in our

Our business model
For more information see BP at a glance on pages 4-5.



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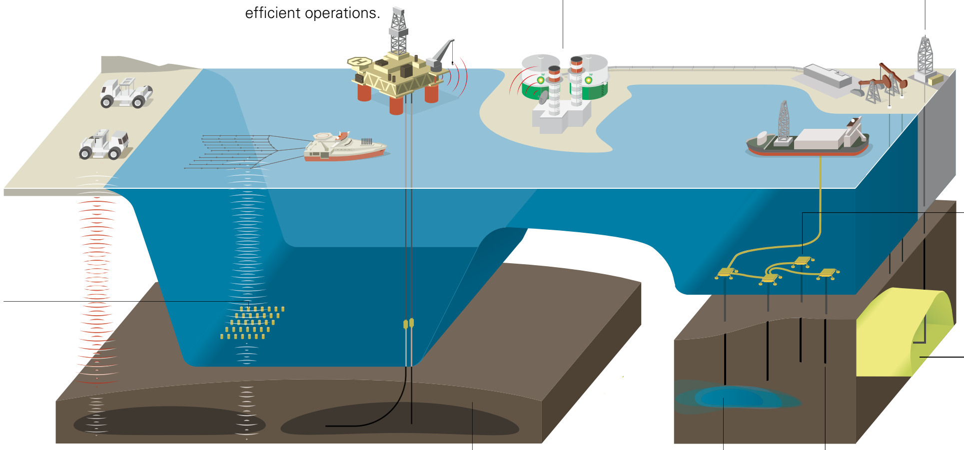
[a] Actual amount of proved reserves of such fields on a basis recognized by the SEC may be less than this.

Upstream technology flagships



Field of the Future
Applying real-time data capabilities to enable safe and efficient operations.

Inherently reliable facilities
Managing and reducing integrity risk.

Well advisor
BP deliver safe, reliable and efficient well operations through the integration of real-time data.

Advanced seismic imaging
Locating and accessing new resource through industry-leading imaging.

Deepwater facilities
Delivering fully qualified integrated production technology solutions that safely maximise value from BP's deepwater portfolio.

Unconventional gas
Recovering gas from unconventional rocks using innovative technologies.

Heavy oil
Developing new technologies to recover heavy oil.

Beyond sand control
Maximizing production and managing risk from sand-prone reservoirs.

Pushing Reservoir Limits
Growing recovery factors to maximize resources from existing oil fields.

Technology
For more on the role of technology at BP see pages 57-59.

Upstream
For more on our upstream activities in 2012 see pages 63-71.

We increased our acreage in Trinidad & Tobago, where our production comprises oil, gas and NGLs, by 889,000 acres in 2012. Below is the Rowan drilling platform, offshore Trinidad.

industry by participating in industry bodies, engaging with our peers on important issues, and – where appropriate – setting voluntary standards above those required by current regulation. And we carry out regular reviews and audit processes with contractors and suppliers, which help to maintain strong links across our operations and activities.

Technology

We believe our development and application of technology is central to our reputation and competitive advantage. For us, technology is the practical application of scientific knowledge to manage risks, capture business value and inform strategy development. This includes the research, development, demonstration and acquisition of new technical capabilities and support for the deployment of BP's know-how.

Our investments are focused on access to resources, process efficiency, product formulation and lower-carbon opportunities. We monitor the potential opportunities and risks presented by emerging science, interdisciplinary innovation and new players; natural resource issues and climate concerns; and evolving policy, including the current emphasis on energy security and efficiency.

BP's technology advisory council, comprised of eminent business and academic technology leaders, provides the board and executive management with an independent view of BP's capabilities judged against the highest industrial and scientific standards.

Supply and trading

We buy and sell at each stage in the value chain to optimize value for the group, often selling our own production and buying from elsewhere to satisfy demand from our refineries and customers. We also aim to create value through entrepreneurial trading, where our presence across major energy trading hubs gives us a good understanding of regional and international markets.

Upstream

Our Upstream segment is responsible for our activities in oil and natural gas exploration, field development and production, and midstream transportation, storage and processing. We also market and trade natural gas, including liquefied natural gas, power and natural gas liquids. We focus on areas that play to our strengths, particularly exploration, deep water, gas value chains and giant fields.

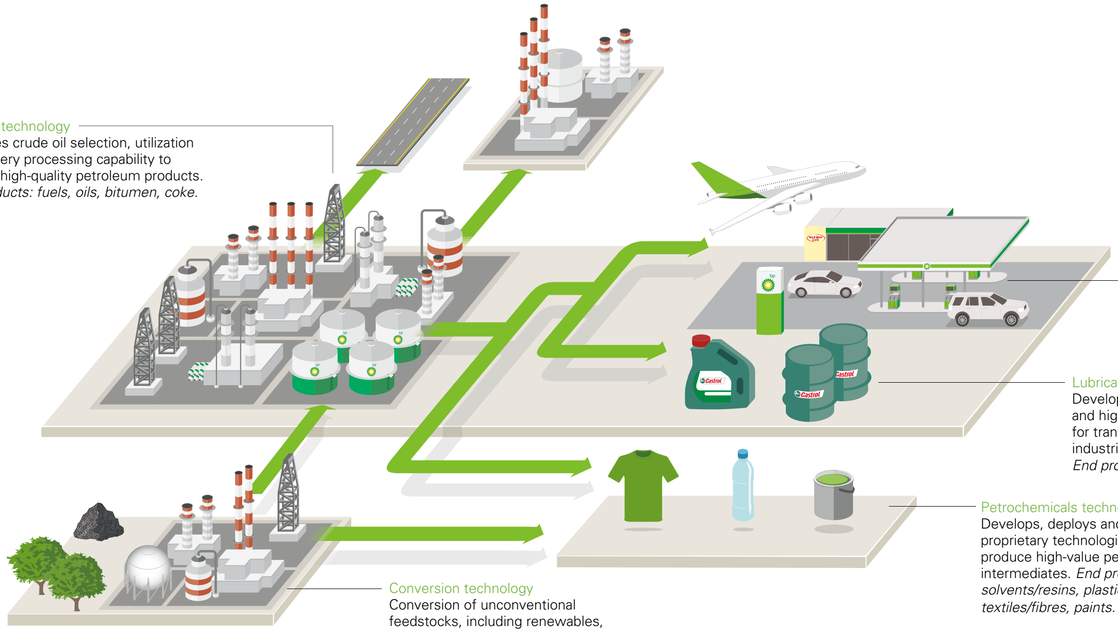
In 2012 our upstream and midstream activities took place in 28 countries including Angola, Azerbaijan, Canada, Egypt, Norway, Trinidad & Tobago, the UK, the US and other locations within Asia, Australasia, South America, North Africa and the Middle East.

Our Upstream segment manages its exploration, development and production activities through global functions with specialist areas of expertise.

We actively manage our portfolio and are placing increasing emphasis on accessing, developing and producing from fields able to provide high-margin barrels (those with the potential to make the greatest contribution to our operating cash flow). We sell assets when we believe they may be more valuable to others. This allows us to focus our leadership, technical resources and organizational capability on the resources we believe are likely to add the most value to our portfolio.

Our upstream technologies support BP's business strategy by focusing on safety and operational risks, helping to obtain new access, increasing recovery and reserves and improving production efficiency. Our strengths in exploration, deep water, giant fields and gas value chains are underpinned by dedicated flagship technology programmes.

Downstream technology



Refining technology
Optimizes crude oil selection, utilization and refinery processing capability to produce high-quality petroleum products.
End products: fuels, oils, bitumen, coke.

Fuels technology
Develops and implements new high-efficiency fuel products.
End products: gasoline, diesel, aviation fuel, marine fuel.

Lubricants technology
Develops unique lubricants and high-performance fluids for transportation and industrial applications.
End products: lubricants.

Petrochemicals technology
Develops, deploys and optimizes proprietary technologies to produce high-value petrochemicals intermediates. *End products: solvents/resins, plastics, textiles/fibres, paints.*

Conversion technology
Conversion of unconventional feedstocks, including renewables, to fuels and petrochemicals.

Downstream
For more on our downstream activities in 2012 see pages 72-79.

The lubricants business is focusing on the growth markets of Brazil, India and China. Below, a Castrol laboratory technician in Brazil, where *Castrol* lubricants have been sold since the 1950s.

Downstream

Our Downstream segment is the product and service-led arm of BP, focused on fuels, lubricants and petrochemicals. It is responsible for the refining, manufacturing, marketing, transportation, and supply and trading of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers.

The Downstream segment markets products in over 70 countries and has significant operations in Europe, North America, Australasia and Asia. We also manufacture and market our products across southern Africa and Central and South America.

We aim to be excellent in the markets in which we choose to participate – those that allow BP to serve the major energy markets of the world. Our aim is to operate all of our businesses as safe and reliable value chains, where we participate in multiple stages of each supply chain, as we believe that way we can deliver greater returns than would arise from owning a collection of discrete assets. These value chains, combined with our advantaged manufacturing operations and expertise in technology, allow us to pursue competitive returns and sustainable growth, as we serve customers and promote BP and our brands through high quality products. As in our Upstream segment, we will sell assets when we believe that to do so would generate more value than retaining them in our own portfolio.

Technology makes a critical contribution to our downstream activities. Through the research, development and deployment of a wide range of technologies, processes and techniques, we aim to enhance safety and risk management, improve our margins, increase efficiency and reliability, and create new market opportunities. For example, in lubricants we launched an oil co-engineered with Ford during the development of its newly released EcoBoost™ engine, which offers a significant improvement in efficiency.

The segment comprises three businesses: fuels, lubricants and petrochemicals, each of which operates as a value chain.

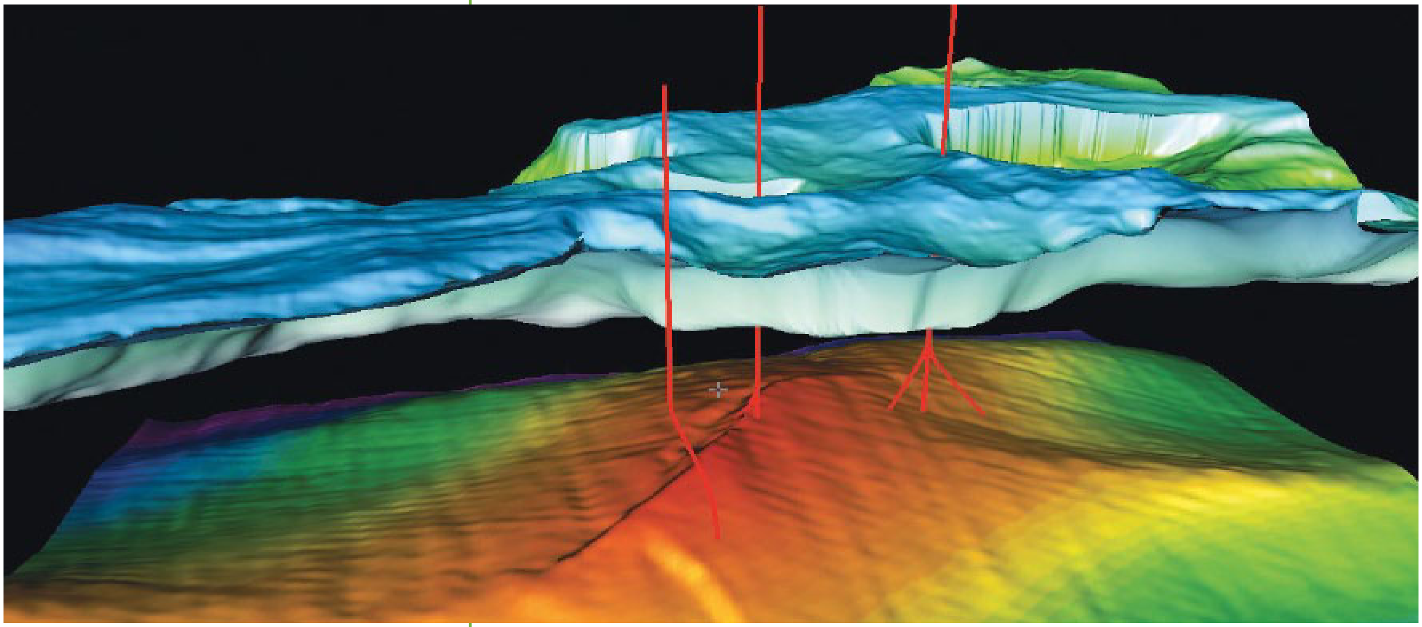
Our fuels business sells refined petroleum products including gasoline, diesel and aviation fuel and liquefied petroleum gas. Within the fuels business, fuels value chains integrate the activities of refining, logistics, marketing, and supply and trading on a regional basis. This provides the opportunity to optimize our activities – from crude oil purchases to end-consumer sales – all the way through our refineries, terminals, pipelines and retail stations.

Our lubricants business is involved in manufacturing and marketing lubricants and related services to markets around the world. We add value through the strength of our brands and through strategic collaboration with original equipment manufacturing partners where we seek to develop new high-performance lubricants such as *Castrol EDGE*.

Our global petrochemicals business manufactures and markets petrochemicals that are used in many everyday products, such as paints, plastic bottles and textiles. Value is derived from our strong customer relationships and joint-venture partners, and through the application of our world-class, proprietary technology.

Our strategy

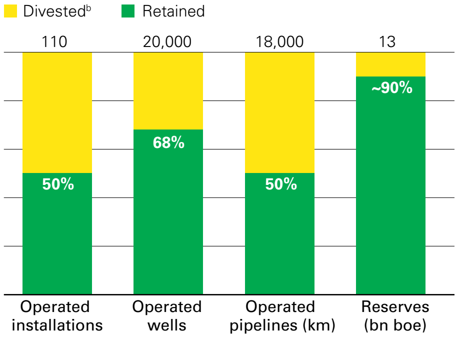
Through our strategy we aim to create a distinctive platform for value growth over the long term.



Our seismic technology helps minimize field appraisal and development risk. The above model of a hydrocarbon field in the Gulf of Mexico shows large salt deposits obscuring a hydrocarbon reservoir.

Upstream portfolio simplification

We have divested a significant proportion of our operated assets while still retaining virtually all our future major projects[a] and around 90% of our proved reserves.



[a] See pages 67-71 for information on our major Upstream projects.
[b] Since April 2010.

In 2011 we put forward a 10-point plan that outlined what could be expected from BP over the next three years. During 2012 we worked towards the milestones we had set out for 2014. We refined our plans and communicated further information on our longer-term strategic objectives beyond 2014.

Through this work and the actions taken to strengthen the group, BP enters 2013 a more focused oil and gas company with promising opportunities and a clear plan for the future. BP's strengthened position, distinctive capabilities, strong financial framework and vision for the future provide the foundation for our long-term strategy. This strategy is intended to ensure BP is well positioned for the world we see ahead.

Our financial framework

We expect our organic capital expenditure[a] to be in the range of $24-27 billion per year through to the end of the decade, with investment prioritized towards the Upstream segment. All investments will continue to be subject to a rigorous capital allocation review process.

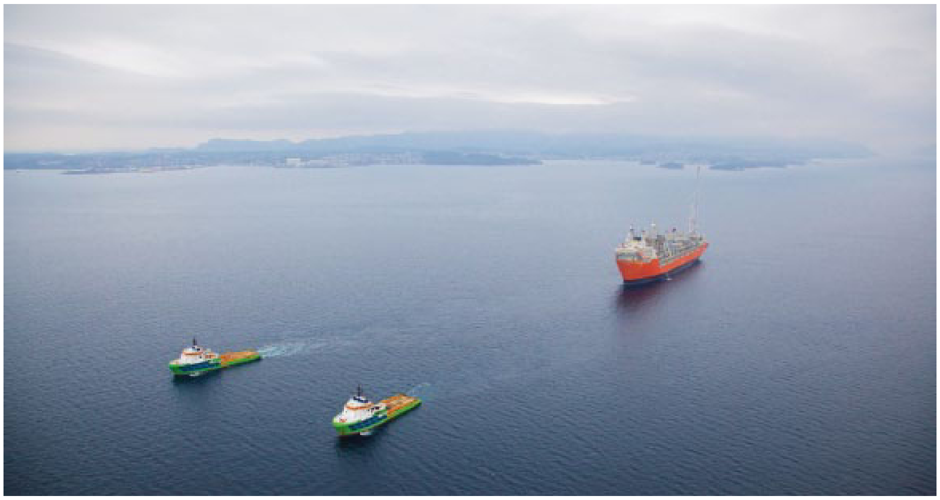
We expect to make around $2-3 billion of divestments per year in order to constantly optimize our portfolio. We will target gearing[b] in the 10-20% range while uncertainties remain. Our intention is to increase shareholder distributions in line with BP's improving circumstances.

Our strategic priorities

Our aim is to be an oil and gas company that grows over the long term. We will seek to continually enhance safety and risk management, earn and keep people's trust, and create value for shareholders. We will continue to simplify our organization and fine tune the portfolio. We will focus on efficient execution in our operations and our use of capital. We will build capability through the pursuit of greater standardization and increased functional expertise.

BP Energy Outlook 2030 projects that world demand for energy will continue to grow. In helping to meet this demand, BP has a large suite of opportunities – the legacy of years of success in gaining access to and developing resources. This allows us to select and invest in those projects with the potential to provide the highest returns. We will prioritize value rather than seek to grow production volume for its own sake. We will concentrate on higher quality assets in both our Upstream and Downstream segments, starting with safety and the delivery of strong and growing cash flows to the group.

[a] Organic capital expenditure excludes acquisitions and asset exchanges.
[b] See footnote d on page 21.



The Skarv floating production, storage and offloading unit – one of the major project start-ups in 2012 – on tow in a Norwegian fjord.

10-point plan

Launched in October 2011 and set out in *BP Annual Report and Form 20-F 2011*, our 10-point plan described our intentions for building a stronger, safer BP.

What you can expect

1 A relentless focus on safety and managing risk through the systematic application of global standards.

2 We will play to our strengths in exploration, deep water, giant fields and gas value chains.

3 Stronger and more focused with an asset base that is high graded and higher performing.

4 Simpler and more standardized with fewer assets and operations in fewer countries; more streamlined internal reward and performance management processes.

5 Improved transparency through reporting TNK-BP as a separate segment and breaking out the numbers for the three downstream businesses.

What you can measure

6 Active portfolio management to continue by completing $38 billion of disposals over the four years to the end of 2013, in order to focus on our strengths.

7 We expect to bring new upstream projects onstream with unit operating cash margins[a] around double the 2011 average by 2014.[b]

8 We are aiming to generate an increase of around 50% in net cash provided by operating activities by 2014 compared with 2011.[c]

9 We intend to use half our incremental operating cash for reinvestment, half for other purposes.

10 Strong balance sheet with intention to target our level of gearing[d] in the lower half of the 10-20% range over time.

We will pursue new opportunities by applying our distinctive strengths of relationships, technology and a strong balance sheet. Our past experience of co-ordinating complex projects around the world can help us to gain access to new areas.

Business model
For more information on our distinctive strengths and how we create value see pages 15-19.

Upstream

Our analysis indicates that oil offers us the most attractive opportunities. Our investments will therefore be biased to oil. We also believe there will be opportunities to create high returns from advantaged gas assets.

We have a long track record of value creation through **exploration**. We will invest in our strong incumbent positions and look for new opportunities. **Deepwater** developments can provide good opportunities for companies with the requisite expertise. We will utilize our scale and capability as we invest further in this area. We believe we are able to manage scale and complexity, and improve the recovery of conventional and unconventional resources. We expect to continue to invest in **giant fields**, where this expertise is particularly valuable.

We believe our ability to integrate complex **gas value chains** is another key strength. We intend to hold a portfolio of gas positions selected according to expected returns, with a balance across conventional and unconventional gas. We will optimize these through our trading activities.

We are committed to Russia and the Middle East – areas where we have a long history.

Downstream

We believe BP has world-class downstream operations with a strong and improving track record of performance in recent years. We will continue to focus on safe and reliable operations and excellent execution, together with disciplined investment and portfolio management. Our focus on portfolio quality will include improving the margin capability of all of our businesses, and a focus on investing in attractive markets.

As the world changes, we expect to increase our exposure to growth markets and demand from new consumers.

Longer-term objectives

→ Maintain momentum on safety and risk reduction.

→ Develop and apply new technologies that access new hydrocarbons or extract and process them more efficiently.

Upstream

→ Generate strong returns within a disciplined financial framework.

→ Deliver growth through increased reinvestment in higher return opportunities.

→ Maintain our strong incumbent positions and a diversified portfolio of deep water, giant fields and gas value chains.

→ Build material new positions for the long term.

Downstream

→ Grow free cash flow.[e]

→ Reduce our exposure to refining when not part of an integrated value chain.

→ Re-orientate the geographic mix of our downstream footprint to growth markets.

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[a] Unit cash margin is net cash provided by operating activities for the relevant projects in our Upstream segment, divided by the total number of barrels of oil and gas equivalent produced for the relevant projects. It excludes dividends and production for TNK-BP.

[b] Assuming a constant oil price of $100 per barrel.

[c] Assuming an oil price of $100 per barrel and a Henry Hub gas price of $5/mmBtu in 2014. The projection assumes the completion of the agreed transaction with Rosneft and receipt of the projected Rosneft dividend and excludes BP's share of the TNK-BP dividends from operating cash flow for 2011 and 2014. The projection includes BP's payment commitments under the Department of Justice and SEC settlements. It does not reflect any cash flows relating to other liabilities, contingent liabilities, settlements or contingent assets arising from the Gulf of Mexico oil spill which may or may not arise at that time. We are not able to reliably estimate the amount or timing of a number of contingent liabilities. See Financial statements – Note 43 on page 253 for further information.

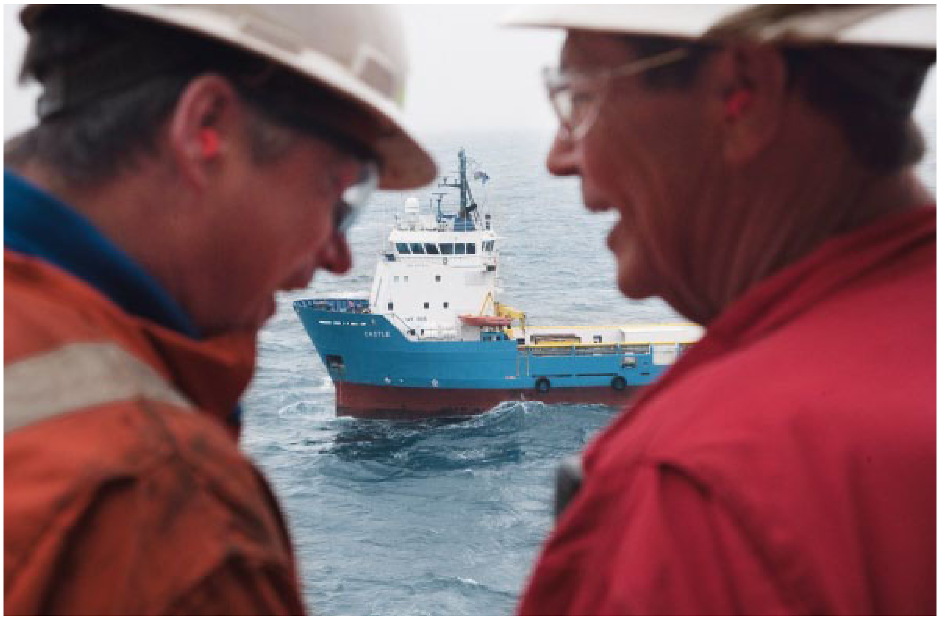
[d] Gearing refers to the ratio of the group's net debt to net debt plus equity and is a non-GAAP measure. See Financial statements – Note 35 on page 234 for further information including a reconciliation to gross debt, which is the nearest equivalent measure on an IFRS basis.

[e] Free cash flow: net cash provided by operating activities less net cash used in investing activities.

Our performance

2012 saw BP build on the strong foundations laid in the previous year. Despite facing major uncertainties, we made progress against our 10-point plan and are reshaping our portfolio to increase efficiency, margins and cash flows.

In 2012 our refineries – particularly Toledo (above) and Whiting in the US – benefited from a location advantage, as they were able to access discounted crudes.



BP has been in Azerbaijan since 1992 and is the largest foreign investor in the country. Our assets include the West Chirag production and drilling platform (right) which is due to start up in late 2013.

During the year we made progress in our priority areas of enhancing safety and risk management, restoring trust by meeting our commitments in the Gulf of Mexico and delivering higher returns for shareholders, as evidenced by the increases in quarterly dividend announced in 2012 (see Dividends on page 25). We worked to resolve the uncertainties facing the company in the US and Russia. We continued the major programme of divestments announced in 2010, which we believe is making BP a more efficient organization. And we made investments in areas where we believe we have advantages and higher margin opportunities. Safety remained our number one priority throughout the year, across the company.

We reached the majority of the 2012 milestones that we set out when we launched our 10-point plan in October 2011 (see 2012 in summary) and believe we are on course to improve our margins and cash flow by 2014.

Safety

We continued our work to enhance safety and risk management in everything we do. In personal safety, sadly, we had four fatalities in our operations during 2012. We reported 43 Tier 1 process safety events in 2012 and 74 in 2011. Loss of primary containment was reduced by 19% compared with 2011. We continued our programme of major upstream turnarounds, with 30 turnarounds completed in 2012. We expect to carry out up to 22 further turnarounds in 2013.

Over the past 12 months, our safety and operational risk function (S&OR) continued to drive improvements to operational safety and reliability with enhanced independent assurance, improved engineering and operating practices, and training and coaching programmes. Our single global wells organization is driving greater consistency across our operations. Our performance and reward system is reinforcing that everyone at BP is responsible for safe operations.

BP's operating management system (OMS) provides us with a systematic and controlled approach to the way the company's operating facilities are managed. All of our operations, with the exception of those recently acquired, are now applying OMS and working to conform to these group-wide standards and practices.

We continue to make progress on all of the remaining recommendations from the Bly Report. As of December 2012, the total number of completed recommendations was 14 out of 26.

Independent advice and monitoring

In June 2012 we appointed Carl Sandlin to track the company's implementation of the recommendations of the Bly Report, our internal investigation into the Deepwater Horizon incident. He brings extensive experience in overseeing global drilling operations. In this role, he will provide an objective and independent assessment to the board of BP's progress against the report's recommendations. He will also observe and report on process safety culture.

Following legal settlements with the US government, BP has agreed to take additional actions, enforceable by the court, to further

Safety
For more information on our safety performance see pages 46-50.

$20 billion

Total BP payments made to the Deepwater Horizon Oil Spill Trust fund.

$11.6 billion

BP's profit[a] in 2012.

$12.0 billion

BP's replacement cost profit[a b] in 2012.

[a] Profit attributable to BP shareholders. This is the measure of profit required for the group under IFRS.

[b] Replacement cost profit reflects the replacement cost of supplies and, for the group, is not a recognized GAAP measure. See footnote b on page 34.

enhance the safety of drilling operations in the Gulf of Mexico (see US regulatory update on page 24). These actions include the appointment of two monitors, both with terms of four years. A process safety monitor will review, evaluate, and provide recommendations for the improvement of BP's process safety and risk management procedures concerning deepwater drilling in the Gulf of Mexico. An ethics monitor will review and provide recommendations for the improvement of BP's code of conduct and its implementation and enforcement. Additionally, an independent third-party auditor will review and report on BP's implementation of key terms of the agreement, including procedures and systems related to safety and environmental management, operational oversight, and oil spill response training and drills.

Trust

BP has continued to meet its commitments to the Gulf Coast. During the year we worked with state and federal trustees to assess impacts on natural resources and progress early environmental restoration work. We supported independent research through the Gulf of Mexico Research Initiative, so we can better understand and mitigate the potential impacts of future oil spills. And we continued to clean up the Gulf shoreline, which involved responding promptly when Hurricane Isaac brought deposits of buried residual oil to the surface at some beaches. Of the 4,376 miles (7,043km) that were in the area of response covered in the Shoreline Clean-up Completion Plan[a], 4,029 miles (6,484km) were deemed complete by the end of 2012.

We have continued to promote economic recovery by resolving legitimate claims and providing support to two of the region's most important industries – tourism and seafood. In the fourth quarter we made a final payment into the Deepwater Horizon Oil Spill Trust fund (Trust), bringing our total payments to $20 billion. The Trust and BP had paid a total of $11.7 billion in claims, advances and other payments by the end of 2012.

Settlement reached with PSC

In April we announced we had reached definitive and fully documented agreements with the Plaintiffs' Steering Committee (PSC) to resolve the substantial majority of eligible private economic loss and medical claims stemming from the Deepwater Horizon accident and oil spill. The agreements were approved by the court in December 2012 and January 2013 although BP is challenging a recent ruling by the court regarding the interpretation of certain protocols established in the economic and property damages settlement agreement. See Legal proceedings on page 167. The settlement includes BP's commitment of $2.3 billion to help resolve economic loss claims related to the Gulf seafood industry.

[a] Approved by the US Coast Guard's Federal On-Scene Coordinator, the Shoreline Clean-up Completion Plan sets standards for the surveying, verification and completion of clean-up activities.

2012 in summary

- We drew our TNK-BP partnership in Russia to a close through an agreed transaction with Rosneft, which will provide BP with a net $12.3 billion in cash (which includes a dividend of $0.7 billion received from TNK-BP in December 2012) and an additional 18.5% share in Rosneft, bringing our total shareholding to 19.75%.
- We took the total of asset sales announced since the start of 2010 to around $38 billion, effectively reaching our target a year early.
- We gained new exploration access in six countries.
- Our 2012 reserves replacement ratio, on a combined basis of subsidiaries and equity-accounted entities, excluding acquisitions and disposals, was 77%, with net additions to reserves in 2012 being wholly from equity-accounted entities (see page 86).

The following points relate to particular milestones we set for 2012:

- High-margin production was brought back onstream successfully in Angola, the North Sea and other regions during 2012.
- Exploration drilling activity took place at nine wells against a target of 12 because additional time was required to ensure the rigs meet our enhanced safety standards.
- Five major project start-ups were achieved (against a target of six): at Galapagos in the Gulf of Mexico; Clochas Mavacola and block 31 in PSVM in Angola; Devenick in the North Sea; and Skarv in Norway. The Angola LNG plant is being commissioned and is expected to start production in 2013.
- Seven rigs were operational in the Gulf of Mexico in 2012 against a target of eight. An eighth rig is in place on the Mad Dog platform and is being commissioned and tested. It is expected to start up in 2013.
- We made the final payment to the Deepwater Horizon Oil Spill Trust, taking total payments to the Trust to $20 billion.
- In Downstream, we were unable to fully deliver the $2 billion of financial performance improvement[b] since 2009, which we had identified as an opportunity in 2010, due mainly to a significant reduction in the supply and trading contribution in 2012.
- Organic capital expenditure[c] during the year was $23.1 billion compared with our original expectation of around $22 billion.

High-margin production was brought back onstream in 2012 in Angola – where the Deepsea Stavanger rig is currently operating at the Greater Plutonio development.

In 2012 we completed the acquisition of Shell and Cosan Industria e Commercio's interests in aviation fuels assets at seven Brazilian airports, which is an important growth market (below).

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[b] See page 75 for further information on Downstream's performance improvement, which is a non-GAAP measure.

[c] Organic capital expenditure excludes acquisitions and asset exchanges and, in 2012, expenditure associated with deepening our US natural gas and North Sea asset bases (see footnote b on page 35).

US legal proceedings
For more information on our US settlements for criminal and securities claims see pages 162-171.

Financial review
For more on our performance in 2012 see pages 34-37.

400,000km^2
New exploration acreage accessed since 2010.

Significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable through the claims process. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported. In addition, there is further uncertainty in relation to interpretations of the claims administrator regarding the protocols under the settlement agreement and judicial interpretation of these protocols, and the outcomes of any further litigation including in relation to potential opt-outs from the settlement or otherwise. The PSC settlement is uncapped except for economic loss claims related to the Gulf seafood industry. There can be no certainty as to how BP's challenge to the court's ruling will ultimately be resolved or determined. To the extent that there are insufficient funds available in the Trust fund, payments under the PSC settlement will be made by BP directly and charged to the income statement. See Plaintiffs' Steering Committee settlements on pages 60-61 for further information as well as Risk factors on pages 41-42 and Financial statements – Note 36 on page 235.

See page 59 for information on the federal multi-district litigation proceeding in New Orleans (MDL 2179), the first phase of which began on 25 February 2013.

US regulatory update

During the year, the US Department of Justice (DoJ) continued to conduct an investigation into the Deepwater Horizon incident regarding possible violations of US civil and criminal laws. Similarly, the US Securities and Exchange Commission (SEC) continued their investigation regarding possible violations of US securities laws.

BP reached an agreement with the US government in November 2012 to resolve all federal criminal claims arising out of the incident. BP pleaded guilty to 11 felony counts of misconduct or neglect of ships officers relating to the loss of 11 lives; one misdemeanour count under the Clean Water Act; one misdemeanour count under the Migratory Bird Treaty Act; and one felony count of obstruction of Congress. BP will pay $4 billion – including criminal fines and payments to the National Fish & Wildlife Foundation and the National Academy of Sciences – in instalments over a period of five years. The court also ordered, as previously agreed with the US government, that BP serve a term of five years' probation. BP has agreed to take additional actions, enforceable by the court, to further enhance the safety of drilling operations in the Gulf of Mexico. These activities relate to BP's risk management processes, such as third-party auditing and verification, training, and well control equipment and processes such as blowout preventers and cementing.

BP reached a settlement with the SEC in November 2012, resolving the SEC's Deepwater Horizon-related civil claims. BP has agreed to a civil penalty of $525 million and to an injunction prohibiting it from violating certain US securities laws and regulations. BP made its first payment of $175 million in December 2012.

The US Environmental Protection Agency (EPA) announced in November 2012 that it had temporarily suspended BP p.l.c. and other BP companies from participating in new federal contracts. As a result of the temporary suspension, the notified BP entities are ineligible to receive any new US government contracts or renewal of an expiring contract. The suspension does not affect existing contracts BP has with the US government, including those relating to current and ongoing drilling and production operations in the Gulf of Mexico. In February 2013 the EPA issued a notice of mandatory debarment for BP Exploration & Production Inc at its Houston headquarters. Mandatory debarment prevents that company from entering into new contracts or new leases

A new chapter in the North Sea

UK production in the North Sea has almost halved in the past 10 years. But for BP the story is far from over. Having produced some 5 billion barrels to date, we believe our assets could yield considerably more. And there are excellent prospects of finding new opportunities too.

In response, we are working to get the most from existing fields, building new production and exploring for more. 2012 saw us make good progress. We are on course with a five-year, $19-billion programme of investment in the UK North Sea, with our partners. We achieved a planned start-up safely and on time. And we sold a number of non-strategic assets.

BP is currently one of the largest producers of hydrocarbons in the UK. Our investments mean we expect to be part of life in the North Sea for decades to come.

We made good progress on the Whiting refinery modernization programme (right) in 2012, and the project is on track to come onstream in the second half of 2013.

BP is accelerating the commercialization of advanced biobutanol technology – with partner Du Pont – at a purpose-built development and demonstration facility at our Saltend site, near Hull, UK (above).

$22.5 billion

Our Upstream segment's replacement cost profit before interest and tax in 2012.

Upstream
For more on the segment's financial performance see page 65 and for information on segmental changes affecting Upstream at the beginning of 2012 see page 64.

with the US government at those premises. We continue to work with the EPA to resolve suspension and debarment issues.

Value

We achieved a profit of $11.6 billion in 2012 compared with $25.7 billion in 2011. Excluding inventory holding gains, our replacement cost (RC) profit[a] in 2012 was $12.0 billion compared with $23.9 billion in 2011. After adjusting for non-operating items and fair value accounting effects[b], our underlying RC profit[b] was $17.6 billion in 2012 compared with $21.7 billion in 2011. Underlying RC profit is a measure closely tracked by management to evaluate BP's operating performance and to make financial, strategic and operating decisions.

Our goal is to grow operating cash flow[c] to enable us to invest for future growth and increase distributions to shareholders. This year we generated operating cash flow of $20.4 billion, compared with $22.2 billion in 2011. The cash outflow in respect of the Gulf of Mexico oil spill reduced from $6.8 billion in 2011 to $2.4 billion in 2012. Cash and cash equivalents at the end of 2012 totalled $19.5 billion. Gross debt at 31 December 2012 was $48.8 billion compared with $44.2 billion at 31 December 2011. Net debt[a] was $27.5 billion at 31 December 2012, leaving our gearing (net debt ratio)[d] at 18.7% compared with 20.5% at the end of 2011. We continue to target gearing in the 10-20% range while uncertainties remain.

Dividends

Total dividends paid in 2012 were 33 cents per share, up 18% compared with 2011 on a dollar basis and 20% in sterling terms. This equated to a total cash distribution to shareholders of $5.3 billion during the year. We announced two increases in the quarterly dividend during 2012 – by 14%, to 8 cents per share, in February and by a further 12.5%, to 9 cents per share, in October. These increases reflected our confidence in the company's progress against the 10-point plan and our growing belief in its longer-term prospects.

Portfolio reshaped

During the year we strengthened the group's financial position, announcing further asset sales and, by the end of 2012, we had essentially reached our $38 billion target.

We began the divestment programme in 2010, increasing the focus of the company's core portfolio on BP's areas of distinctive strength and capability, while reducing operational complexity. We have since sold around 50% of our upstream installations, 32% of our wells and 50% of our pipelines, while only reducing our proved reserves base by approximately 10% and our production by about 9%. We have traded mature assets with declining cash flows so we can concentrate on assets with greater potential for growth.

In November 2012 we took a major step forward in repositioning BP within Russia, agreeing to sell our 50% shareholding in TNK-BP to Rosneft – the world's largest publicly traded oil company in terms of oil production and reserves. Our intention is to use part of the cash proceeds from the agreed transaction to offset any dilution to BP's earnings per share.

Upstream

We reported RC profit before interest and tax of $22.5 billion, compared with $26.4 billion in 2011. After adjusting for non-operating items and fair value accounting effects, underlying RC profit before interest and tax[e] was $19.4 billion in 2012, compared with $25.2 billion in 2011 reflecting higher costs, lower production and lower realizations.

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[a] Replacement cost profit for the group is not a recognized GAAP measure. The equivalent measure on an IFRS basis is 'Profit for the year attributable to BP shareholders'. See footnote b on page 34 and page 98 for further information.

[b] Underlying replacement cost profit and fair value accounting effects are not recognized GAAP measures. See pages 34, 37 and 98 for further information.

[c] Operating cash flow is shown in our cash flow statement as net cash provided by operating activities.

[d] Net debt and gearing are non-GAAP measures. See footnote d on page 21 for further information.

[e] See footnote b on page 34.

Our performance – continued

Downstream
For more on the segment's financial performance see pages 74-75.

$2.8 billion

Our Downstream segment's replacement cost profit before interest and tax in 2012.

94.8%

Our Solomon refining availability in 2012.

Our focus on safe, reliable and compliant operations has translated into improvements in both personal and process safety. We have seen a 16% improvement in our days away from work case frequency since the start of 2010, and a 22% improvement in our loss of primary containment incidents over the same period.

We have continued to open up new exploration opportunities. In 2012 we added almost 68,000 square kilometres (approximately 26,250 square miles) of new acreage in Brazil, Canada, Egypt, Namibia and Uruguay; and in the Gulf of Mexico and Ohio in the US. The Ohio acreage covers Utica/Point Pleasant, a promising shale basin. Since 2010 we have accessed around 400,000 square kilometres (approximately 154,500 square miles) of new acreage – an area roughly the size of California. This is more than double the acreage accessed by BP from 2000 to 2009.

We made good progress in the four areas we believe most likely to provide us with higher margin barrels – Angola, Azerbaijan, the North Sea and the Gulf of Mexico.

In Angola, we started production at two projects during 2012 (see page 23). We also continued a programme of exploration and appraisal.

In Azerbaijan, the Shah Deniz consortium – a seven-member group led by BP – selected Nabucco West as the single pipeline option for the potential export of gas to Central Europe, while the Trans-Adriatic Pipeline was selected as the potential route for exports to Italy. Negotiations on transit and marketing terms will determine which project will be selected as the route to market, ahead of our final investment decision on Shah Deniz. We remain on course to start up the West Chirag production and drilling platform in late 2013.

In the North Sea, 2012 saw high levels of activity. We achieved start-ups, sold a number of non-strategic assets and moved forward with a major programme of long-term investment (see A new chapter in the North Sea, page 24). These actions reflect our strategy of focusing on higher margin projects.

Although uncertainties about the consequences of the Gulf of Mexico oil spill remain, we believe that the Gulf of Mexico remains an important source of medium and long-term growth. The sale of non-core assets in the region should allow us to concentrate on our four operated hubs, together with further exploration activity. In our existing Gulf of Mexico hubs, 80% of our estimated ultimate recovery is still in the ground. We are also continuing our Paleogene appraisal programme of high temperature/high pressure reservoirs in the Lower Tertiary area.

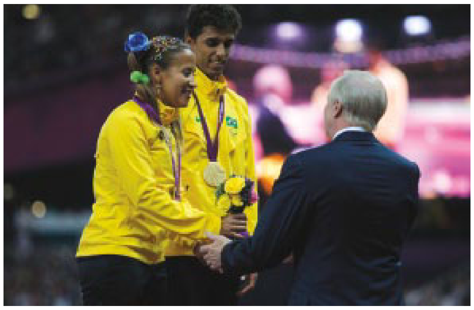
Following an 18-month review that reassessed the technical and economic challenges involved in developing the Liberty field in Alaska safely and profitably, we announced in June that we had suspended our development plans. We are working with regulators to develop alternative plans for the field.

Winning partnerships

As an Official Partner of the London 2012 Olympic and Paralympic Games, BP invested its resources and capabilities over four years to support the Games.

We formed partnerships with the Olympic and Paralympic Committees in the UK, US and seven other countries of strategic importance to BP. We supported 60 athletes as they trained and competed. We provided advanced fuels and engine oils for 5,000 official vehicles and helped offset carbon emissions produced by over half a million spectators' journeys. We also brought the magic of the Olympic and Paralympic Games to millions through the Cultural Olympiad and the London 2012 Festival.

We believe our support to the Games enabled us to improve perceptions of BP and enhance our reputation, with communications and advertising raising public awareness of BP's contribution. The Games also provided an opportunity to strengthen our relationships with many business partners from around the world, who took part in an immersive business 'experience' using innovative visual techniques to demonstrate BP technology. London 2012 was a huge source of inspiration for our employees too, with many having the opportunity to contribute their time and energy to its success.



Investing in renewable energy

Since 2005 we have invested $7.6 billion in lower-carbon businesses and are on track to meet our commitment to invest $8 billion by 2015. In biofuels, our three sugar cane mills in Brazil now have a total crush capacity of 7.2 million tonnes and produce fuels for use in transport and power. At the end of 2012 we started up the Vivergo JV bioethanol plant in Hull, UK. We also have research, demonstration and production facilities planned or operating in the US, UK and Brazil. During the year we cancelled plans to build a commercial-scale cellulosic ethanol plant in Florida and refocused our cellulosic strategy on research, development and technology licensing. In wind we have interests in 16 wind farms in the US, which together provide BP with a net generating capacity of 1,558MW.[a]

Alternative Energy
For more on our activities see Other businesses and corporate page 82.

[a] Excludes 32MW of capacity in the Netherlands, which is managed by our Downstream segment.

TNK-BP
For more on the segment's financial performance see pages 80-81.

PSVM is one of the largest subsea developments in the world and was one of BP's key project start-ups for 2012. It is the second BP-operated development in Angola after Block 18's Greater Plutonio (below).

Downstream

RC profit before interest and tax for 2012 was $2.8 billion, compared with $5.5 billion in 2011. After adjusting for non-operating items and fair value accounting effects, underlying RC profit before interest and tax[b] in 2012 was an all-time record of $6.4 billion compared with $6.0 billion in 2011. This reflected a favourable refining environment, which we were able to capture by virtue of our strong operations, partly offset by weak petrochemicals margins and a significantly lower supply and trading contribution than in 2011. 2012 was also our fourth consecutive year of growth in underlying RC profit before interest and tax. We also continued to make good progress in repositioning Downstream to improve our margin quality and the efficiency of the portfolio.

Since the start of 2008, our focus on safe and reliable operations in Downstream has translated into improvements in process safety. We have seen a 55% reduction in loss of primary containment and a 40% reduction in our process safety incident index over the period.

Refinery operations were strong this year, with Solomon refining availability of 94.8%. (See refining availability on page 74.) Utilization rates were at 88% despite a relatively high level of turnaround activity in 2012.

Our lubricants business continued to deliver robust performance in 2012, despite weak demand.

In petrochemicals, a combination of increased supply and lower demand growth in the market narrowed margins for our business in 2012, although we were able to maintain production volumes at around the same levels as 2011.

During the year we continued to make good progress in repositioning the Downstream business. In August 2012 we announced an agreement to sell our Carson refinery, in California, and related logistics and marketing assets in the region to Tesoro Corporation for an estimated $2.5 billion. In October 2012 we announced an agreement to sell our Texas City refinery and all associated assets in the south-east US to Marathon Petroleum Corporation. This sale was completed on 1 February 2013 for proceeds of up to $2.4 billion (see page 72).

Meanwhile, we made significant progress with the upgrade of our Whiting refinery. On completion, this modernization project is expected to allow us to capture additional margin through the processing of a greater proportion of heavy crudes. During the year the new crude oil unit, coker, upgraded sulphur recovery complex and gasoil hydrotreater all advanced towards their targeted start-up dates in 2013 and the whole project remains on schedule to start up in the second half of 2013.

We also made good progress towards our aim of divesting the LPG bulk and bottled business, completing the exit from three of the nine countries we originally identified and announcing the sale of our operations in a further three countries in 2012.

In petrochemicals we sold our PTA interest in Malaysia during the year and made progress on major new projects in China and India. We also signed two licensing agreements for our proprietary petrochemicals technology (see page 16 for further details).

TNK-BP

We began reporting TNK-BP as a separate operating segment with effect from 1 January 2012, reflecting the way in which we were managing our investment.

Following the announcement of our proposed transaction with Rosneft on 22 October 2012, BP's investment in TNK-BP met the criteria to be classified as an asset held for sale. Consequently, BP ceased equity accounting for its share of TNK-BP's earnings from the date of the announcement.

RC profit before interest and tax[bc] for 2012 was $3.4 billion, compared with $4.1 billion in 2011. After adjusting for non-operating items, underlying RC profit before interest and tax[bc] for 2012 was $3.1 billion, compared with $4.1 billion in 2011. The most significant factor affecting performance in 2012 compared with 2011 was the absence of more than two months' income following the cessation of equity accounting.

[b] See footnote b on page 34.

[c] Under equity accounting, BP's share of TNK-BP's earnings after interest and tax has been included in the BP group income statement within profit before interest and tax.

Outlook

The company's divestment programme is fundamentally reshaping and repositioning our upstream and downstream portfolios. In the Upstream segment, we now have a portfolio that we believe plays to our distinctive strengths and capabilities in exploration, deep water, giant fields and gas value chains. In the Downstream segment, we expect that the measures we are taking to improve efficiency and margin quality will be largely complete by the end of 2013.

Looking ahead, we continue to expect that we can deliver around 50% growth in operating cash flow by 2014 compared with 2011.[d] We intend to use the proceeds of improved cash flow in a number of ways, including increased investment in upstream development. This will focus on four high-margin areas: Angola, Azerbaijan, the Gulf of Mexico and the North Sea.

More development, more exploration

The level of planned activity is reflected in the number of rigs we have at work. Across our portfolio, we had 53 rigs in operation at the end of 2012 – 20 onshore and 33 offshore, including 11 in the deep water. We expect to have around 60 rigs in operation in 2014.

We intend to increase investment in exploration. Our drilling programme is expected to test 15 new plays between 2012 and 2015.

[d] See footnote c on page 21.

Our key performance indicators

We track our performance against key financial and non-financial indicators.

Our board assesses the group's performance according to a wide range of measures and indicators. The 13 key performance indicators on these pages help us measure performance against our strategic priorities – safety, trust and value – and our business plans. We keep these metrics under periodic review and test their relevance to our strategy regularly. We believe non-financial measures – such as safety and an engaged and diverse workforce – have a useful role to play as leading indicators of future performance.

Changes to KPIs

We have changed our employee engagement key performance indicator from a satisfaction measure to one that measures engagement with our strategic priorities of safety, trust and long-term value, as we believe this measure is more closely aligned with our longer-term objectives. Details of our employee engagement are on page 56.

Remuneration

To help ensure that the focus of our board and management is aligned with the interests of our shareholders, certain of these measures are reflected in the annual bonus element of executive remuneration.

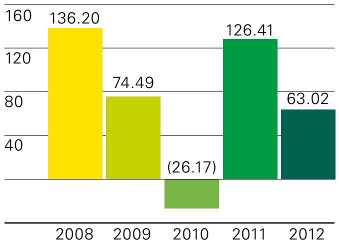
Overall annual bonuses are based on performance relative to measures and targets linked to the annual group plan.

The measures used to determine 2012 and 2013 remuneration are identified with this symbol.

Remuneration
For details of our policy see pages 127-145.

Not all financial KPIs are recognized GAAP measures, but are provided for investors because they are closely tracked by management to evaluate BP's operating performance and to make financial, strategic and operating decisions.

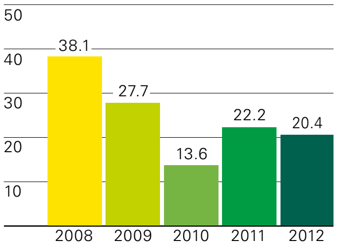
Replacement cost profit (loss) per ordinary share[a] (cents)



Replacement cost profit (loss) reflects the replacement cost of supplies. It is arrived at by excluding from profit inventory holding gains and losses and their associated tax effect. Replacement cost profit for the group is a profitability measure used by management. It is a non-GAAP measure. See page 34 for the equivalent measure on an IFRS basis.

2012 performance Our results were impacted by the cost of the legal settlement agreed with the US government following the Gulf of Mexico oil spill, as well as by lower results in our operating segments.

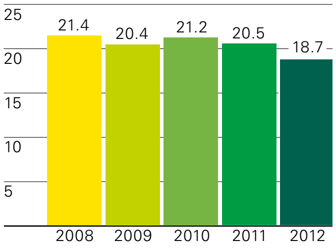
Operating cash flow ($ billion)



Operating cash flow is net cash flow provided by operating activities, from the group cash flow statement. Operating activities are the principal revenue-generating activities of the group and other activities that are not investing or financing activities.

2012 performance Lower operating cash flow in 2012 reflected the cash flow impact of lower profits, which was partly mitigated by a lower cash outflow relating to the Gulf of Mexico oil spill.

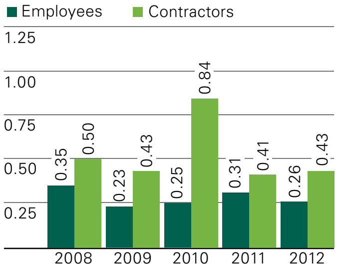
Gearing (net debt ratio)[a] (%)



Gearing enables investors to see how significant net debt is relative to equity from shareholders. Net debt is equal to gross finance debt, plus associated derivatives, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. See Financial statements – Note 35 on page 234 for the nearest equivalent measure on an IFRS basis and for further information.

2012 performance We ended the year with gearing within our desired 10-20% range and we will continue to target this range while uncertainties remain.

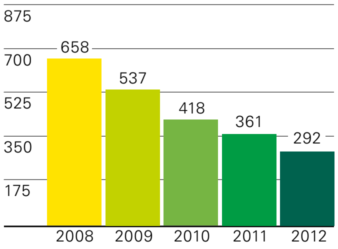
Reported recordable injury frequency[b]



Reported recordable injury frequency (RIF) measures the number of reported work-related incidents that result in a fatality or injury (apart from minor first aid cases) per 200,000 hours worked.

2012 performance Our workforce RIF, which includes employees and contractors combined, was 0.35, compared with 0.36 in 2011 and 0.61 in 2010. The 2010 group RIF was affected by the Gulf Coast response efforts and we continue to focus on improving personal safety.

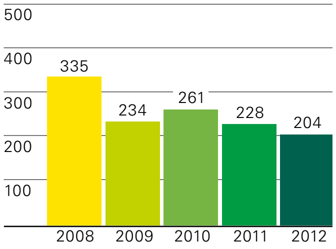
Loss of primary containment[a]



Loss of primary containment is the number of unplanned or uncontrolled releases of material, excluding non-hazardous releases, such as water from a tank, vessel, pipe, railcar or other equipment used for containment or transfer.

2012 performance There was a 19% reduction in loss of primary containment compared to 2011, which continues a year on year improvement. Tracking losses of integrity is a way of measuring safety performance and helping drive improvements.

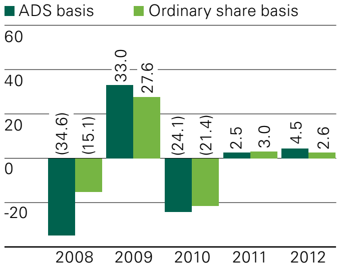
Oil spills[b]



We report the number of spills of hydrocarbons greater than or equal to one barrel (159 litres, 42 US gallons). We include spills that were contained, as well as those that reached land or water.

2012 performance We continue to take measures to strengthen mandatory safety-related standards and processes, including operational risk and integrity management.

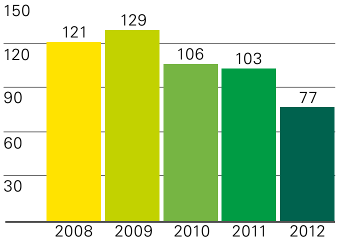
Total shareholder return (%)



Total shareholder return (TSR) represents the change in value of a BP shareholding over a calendar year, assuming that dividends are re-invested to purchase additional shares at the closing price applicable on the ex-dividend date.

2012 performance In 2012 the growth in TSR resulted from increases in the dividend, with the improvement for ordinary shares diminished by exchange rate effects.

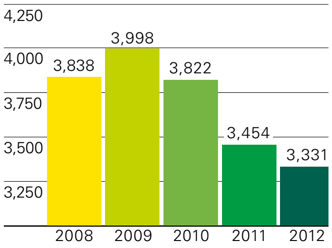
Reserves replacement ratio (%)



Proved reserves replacement ratio (also known as the production replacement ratio) is the extent to which production is replaced by proved reserves additions. The ratio is expressed in oil-equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery and extensions, and discoveries. The measure reflects both subsidiaries and equity-accounted entities, but excludes acquisitions and disposals.

2012 performance Our reserves replacement ratio was impacted by a lower than usual number of final investment decisions related to major projects, lower than expected reservoir performance, and the curtailing or replanning of certain development activities due to lower natural gas prices and higher costs.

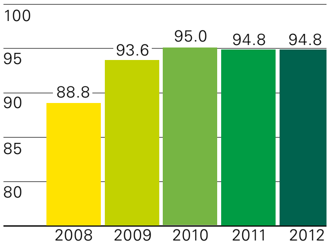
Production (mboe/d)



We report crude oil, natural gas liquids (NGLs) and natural gas produced from subsidiaries and equity-accounted entities. These are converted to barrels of oil equivalent (boe) at 1 barrel of NGL = 1boe and 5,800 standard cubic feet of natural gas = 1boe.

2012 performance BP's total reported production in 2012, including both our Upstream and TNK-BP segments, was 3.6% lower than in 2011, mainly due to the effect of transactions completed in Upstream as part of our $38-billion divestment programme.

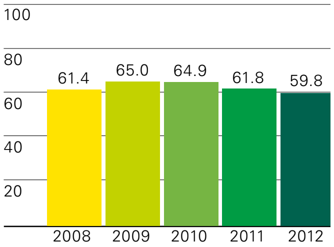
Refining availability (%)



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.

2012 performance Refining availability remained at a high level of 94.8%, reflecting strong operations around our global refining portfolio.

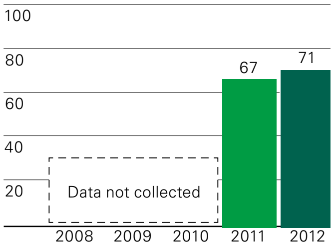
Greenhouse gas emissions (million tonnes of CO_2 equivalent)



We report greenhouse gas (GHG) emissions 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. In 2010 we did not report on GHG emissions associated with the Deepwater Horizon incident or response (see page 52).

2012 performance The 2.0Mte decrease in direct GHG emissions in 2012 is primarily explained by operational changes due to temporary reductions in activity in some of our businesses and by the sale of upstream assets as part of our divestment programme.

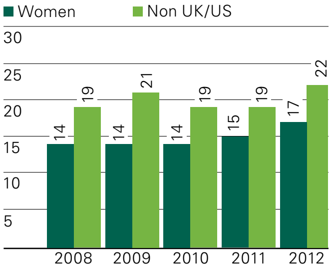
Group priorities engagement[c] (%)



We track how engaged our employees are with our strategic priorities of strengthening safety, earning back trust and building long-term value. The measure is derived from 12 questions about employee perceptions of BP as a company and how it is managed in terms of leadership and standards.

2012 performance Aggregate results for these questions showed a 4% improvement on 2011 to 71%.

Diversity and inclusion[c] (%)



Each year we record the percentage of women and individuals from countries other than the UK and US among BP's group leaders.

2012 performance BP has increased the percentage of female leaders in 2012 and remains focused on building a more sustainable pipeline of diverse talent for the future.

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[a] Not a recognized GAAP measure.

[b] This represents reported incidents occurring within BP's operational HSSE reporting boundary. That boundary includes BP's own operated facilities and certain other locations or situations.

[c] Relates to BP employees.

Our management of risk

Risk management
For information on BP's risk management system see Risk in BP on page 117.

Risk factors
For the risk factors that could have an adverse effect on our business see pages 38-44.

Our system of risk management identifies and provides the response to risks of group significance through the establishment of standardized requirements and controls.

The following is a summary of how we seek to manage the risks we have identified as having a high priority in 2013. There can be no guarantee that our risk management activities will mitigate or prevent these, or other, risks from occurring.

Strategic and commercial risk

We aim to manage risks associated with the general macroeconomic outlook, and changes in prices and markets, by responding to early warnings from our economics and treasury teams and customer-facing businesses. To manage our liquidity, financial capacity and financial exposure risks, we apply our financial framework and we conduct liquidity stress testing and interventions based on scenario planning (see Liquidity and capital resources on pages 90-93).

The diverse locations of our operations around the world expose us to a wide range of political developments and consequent changes to the economic and operating environment. For example, our investments in Russia could be adversely affected by heightened political and other social and environment risks. As such, we try to actively manage our relationships in Russia, including with the Russian federal government. We are also focused on completing our agreement to sell our interest in TNK-BP to, and purchase interests in, Rosneft.

Many of our major projects and operations are conducted through joint ventures or associates and through contracting and sub-contracting arrangements where BP may not have full operational control. We seek to manage the risks arising from such joint venture and contractor relationships actively, and this may include monitoring compliance with applicable standards.

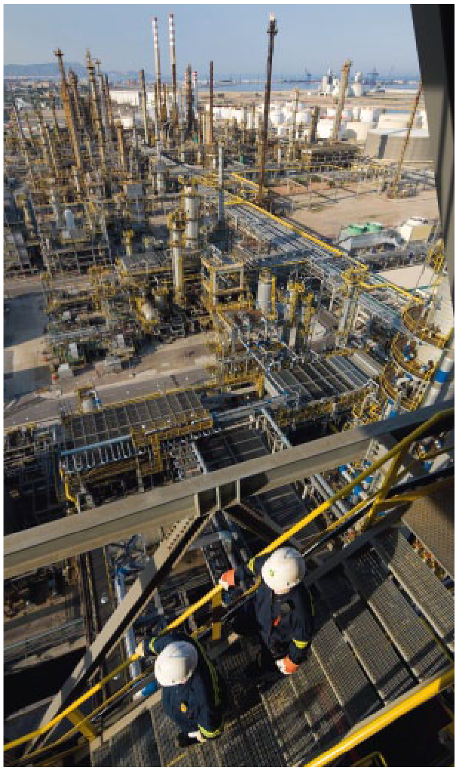
In 2011 we set out a 10-point plan to address our near-term strategic priorities. Among other things, the plan aims to target investments and disposals efficiently, renew and reposition our portfolio and deliver our major projects to plan.

As part of managing the risks to delivery of the 10-point plan we conduct regular planning and performance-monitoring activity, including the planning of disposals; we focus on the successful delivery of major projects; and we pursue the development of continued technological advances and innovation.

A new mission control in Houston

Developed as part of our ongoing commitment to enhance risk management, BP's Houston monitoring centre is a state-of-the-art onshore facility that helps reduce risk by monitoring data from our rig operations in the Gulf of Mexico and providing an additional level of assurance to offshore teams. The facility is similar to the control centre used for space shuttle launches, which is no coincidence – a former senior NASA manager helped to develop its functionality.

Armed with real-time information feeds, live video and constant communication with colleagues on the rigs, teams at the facility monitor data from drilling operations 24 hours a day. Onshore experts are primed to escalate issues up the chain of command offshore if they spot potential incidents. We also monitor the monitors, carrying out a programme of inspections and emergency drills to test the resilience of this collaborative early warning system.



Operators descending coker structure, Castellon oil refinery, Castellon, Spain.

We seek to manage our reputation through actively managing our relationships with key stakeholders and through clear, consistent and coherent communications. We seek to engage with local communities in order to foster improved relationships.

There have been many important developments in 2012 related to the Deepwater Horizon accident, oil spill, and response including the agreement reached with the US government to resolve all federal criminal claims and with the SEC regarding its securities claims. There remains, however, continuing uncertainty regarding the final extent and timing of civil costs and liabilities relating to the incident (with the trial to address many of these issues, which started on 25 February 2013). Further, BP is in ongoing discussions with the EPA to lift the temporary suspension and mandatory debarment. As such, the long-term impact of the incident on our reputation remains uncertain.

In addressing these risks we have been working to review and adapt where necessary our current controls and procedures to assure compliance with the requirements contained within the settlements.

In addition we have been preparing for trial while remaining open to settlement of the remaining civil claims on reasonable terms. We are committed to rebuilding trust with all our stakeholders and continue to co-operate with all investigators, monitors and regulators. Further, we are clear that we always seek to comply with local regulations and, in some cases, our required practices will exceed regulations if our assessment of the operating risk indicates it would be beneficial to do so.

Safety and operational risk

The nature of the group's operations exposes us to a wide range of significant health, safety and environmental risks such as incidents associated with the drilling of wells, operation of facilities, transportation of hydrocarbons and product quality. In addressing these risks we seek to apply our operating management system (OMS), including group and engineering technical practices, as applicable.

We seek to conduct maintenance and equipment testing and to apply product quality control and testing procedures. We also provide our staff with training and competency development. To better manage the risks inherent in drilling wells where we are the operator, we conduct activity through a global wells organization that is accountable for systems and processes for designing, constructing and managing wells.

We have also appointed an independent adviser to provide oversight and assurance regarding the company's implementation of the Bly Report's recommendation and to report on observed process safety culture.

Crisis and continuity management plans, including in respect of oil spill preparedness and response, have been developed to help us to respond effectively to emergencies to minimize impacts and to avoid potentially severe disruption in our business and operations. See Safety on pages 46-50 for information on the recommendations of BP's internal investigation into the Deepwater Horizon oil spill and the actions we are pursuing to address them.

Security threats require continuous monitoring and control as hostile actions against our staff, our facilities (as in the In Amenas joint venture in Algeria) and our digital infrastructure (cyber security) could cause harm to people and could disrupt our operations. We have procedures that are intended to monitor for threats and vulnerabilities and policies to manage our physical and digital security. We also maintain disaster recovery, crisis and business continuity management plans.

Compliance and control risk

Ethical misconduct or breaches of applicable laws or regulations could be damaging to our reputation, results of operations and shareholder value and could affect our licence to operate. Central to managing these risks is our code of conduct and our values and behaviours (see page 56), the requirements of which apply to all employees, supported by our various group requirements covering issues such as anti-bribery and corruption, anti-money laundering, competition/anti-trust law compliance and trade sanctions. We seek to monitor for new regulations and legislation and plan our response to them. We also operate a range of compliance training and monitoring programmes for our employees, including OpenTalk, our confidential helpline for employees.

In the normal course of business, we are subject to risks around our treasury and trading activities, which could arise from shortcomings or failures in our systems, risk management methodology, internal control processes or employees. In addressing these risks, we have adopted specific operating standards and control processes, including guidelines in relation to trading, and seek to monitor compliance through dedicated compliance organizations. We also seek to maintain a positive and collaborative relationship with regulators and the industry at large.

Cautionary statement

This document contains certain forecasts, projections and forward looking statements – that is, statements related to future, not past events – 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', 'anticipates', 'plans', 'we see' or similar expressions. In particular, among other statements, (i) certain statements in the Chairman's letter (pages 8-9), the Group chief executive's letter (pages 10-11), the Business review (pages 3-99) and Additional disclosures (pages 161-175), including but not limited to statements under the headings 'Energy outlook', 'Our strategy', 'Outlook' and 'Looking Ahead', with regard to expectations regarding BP's agreement with and prospective shareholding in Rosneft, including BP's expectations regarding its representations on the Rosneft board, the composition of the board of directors, expectations regarding our strategy and strategic priorities including our Upstream and Downstream strategies and our longer term objectives, plans to deliver shareholder value, plans to continue to simplify the organization and portfolio, plans to focus on efficient execution and use of capital, plans to prioritize value rather than seeking to grow production volume for its own sake, prospects for the settlement of outstanding claims related to the Gulf of Mexico oil spill, plans to continue to meet commitments in the Gulf Coast region, plans to implement the recommendations of the Bly Report, plans to appoint two independent monitors and an independent auditor, BP's intention to prioritize operating cash flow and replacement cost operating profit over barrels of production, plans to work to focus and improve the business, plans to enhance safety and earn back trust, anticipated increases in regulation and taxation of the energy industry and energy users, projections regarding the ability of renewable energy sources to meet total energy demand, expectations regarding investments in proprietary technology, expectations regarding *LoSal* technology, plans to sell assets and entities, expectations regarding the future level of capital expenditures through the end of the decade, expectations regarding the amount of divestments per year, the expected level of gearing, expectations regarding the '10-point plan', expectations regarding future dividend payments and BP's plans to continue to pursue a progressive dividend policy, BP's outlook on global energy trends to 2030 and beyond, BP's outlook on its ability to meet the growing demand for energy, the intention to make $2-3 billion in disposals per annum on an ongoing basis, BP's plans to grow operating cash flow and margins by 2014 and the expected quantum of growth, plans for the use of expected improved cash flow, plans to grow free cash flow in Downstream, expectations regarding the level and types of investments and divestments, expectations regarding the Shah Deniz consortium, BP's plans for involvement in growth markets, the anticipated timing for completion of the disposition of certain BP assets and entities and estimates of the final proceeds therefrom, future production levels including expectations for an increase in high-margin production, the timing and composition of future projects including expected Final Investment Decisions, start-up, construction, commissioning, completion, timing of production, level of production and margins, expectations for drilling and rig activity in the Gulf of Mexico, the timing of measures taken to improve efficiency and margin quality, expectations for the number of rigs in operation, the timing of the delivery of new tankers and rigs, expectations regarding turnover time and the volume of proved undeveloped reserves held for more than five years, the estimated cost of the settlements with the Plaintiffs' Steering Committee in MDL 2179, the expected amount, source and timing of payments under any settlements related to the Gulf of Mexico oil spill, expectations with regard to the terms of any settlements and BP's compliance therewith, the anticipated effect of accounting changes on BP's earnings and cash flow, the timing of the positioning of well cap systems and dispersant application equipment packages, expectations regarding employee training, expectations for an increase in the carbon intensity of operations, expectations regarding environmental research, plans regarding the launch of BP's human rights policy, expectations regarding regulation and taxation of the energy industry and energy users, BP's expectations with regard to employee diversity and inclusion, the timing for completion of and prospects for the High-Performance Computing centre in Houston, prospects for debarment of BP entities and the expected duration and consequences of any such debarment, the timing of the commissioning of the LNG train at Tangguh, plans to retain the petrochemicals manufacturing plants at Texas City, expectations regarding future levels of capital investment, plans regarding Project *20K*, the expected impact of the expiry of the Abu Dhabi onshore concession, plans regarding environmental restoration of the Gulf Coast, future global refinery capacity and utilization, plans and timing for the completion of the upgrade to and start-up of the Whiting refinery, plans regarding upgrades to the Cherry Point refinery, expectations regarding oil price movements in 2013, expectations regarding the gas market in 2013 and the expected drivers thereof, prospects for the persistence in a large gap between US and European gas prices in 2013, BP's plans to license back the *ARCO* brand, prospects for Upstream's contribution to BP's plans to increase operating cash flow by around 50% by 2014, expectations regarding the unit operating cash margins of new upstream projects, BP's strategies with regard to optimizing value across the business, plans regarding BP's PTA project, the timing of a review of BP's assets and estimation processes, plans regarding the implementation of enhancements to BP's risk management system, expectations regarding refining margins, expectations regarding the market for lubricants and petrochemicals, expectations regarding Downstream capital expenditures, expectations regarding the reduction of net debt and the net debt ratio, the expected future level of depreciation, depletion and amortization, the completion of planned and announced divestments, expectations regarding the announced disposal of TNK-BP to Rosneft and acquisition of an 18.5% shareholding in Rosneft, BP's intentions to use part of the cash proceeds from the planned disposal of TNK-BP to offset any dilution to BP's earnings per share, expectations about BP's future investments and operations in the North Sea, expectations regarding reported production and underlying production in Upstream, expectations regarding Vivergo, the timing of the completion of the Angola LNG plant, the timing for the completion of the Mad Dog spar, and the level of future turnaround activity; (ii) the statements in the Business review (pages 3-99), Corporate governance (pages 101-126), the Directors' remuneration report (pages 127-145), and Shareholder information (pages 153-159) with regard to the board's goals and plans stemming from the board's annual evaluation, expectations regarding the timing of events with investors, plans to continue the ongoing process of embedding OMS and to ensure joint venture partners follow principles similar to those of the OMS, plans and timing for the implementation of the Bly report recommendations, plans regarding investments in research, the timing of projects, programs and initiatives, intentions to continue monitoring process safety at TNK-BP, intentions to implement group-wide practices for oil spill preparedness and response and crisis management, plans to spend $700 million on certain refinery-related safety measures, plans to implement enhanced and standardized technical practices across the refining business, the timing of, cost of, source of payment and provision for future remediation and restoration programmes and environmental operating and capital expenditures, plans to halve US refining capacity, plans and expectations with regard to the remuneration, pensions and other benefits of executive directors, expectations regarding the impact of various regulations upon BP's business and expectations regarding greater regulation and increased operating costs in the Gulf of Mexico in the future; (iii) the statements in the Business review (pages 90-93) with regard to future dividend and optional scrip dividend payments, future capital expenditures and capital expenditure commitments, taxation, intentions to maintain a significant liquidity buffer, future working capital and cash flows, gearing and the net debt ratio, BP's intention to maintain a strong cash position, expectations regarding taxes due upon repatriation of cash into the UK, expectations regarding total capital expenditure, expected payments under contractual and commercial commitments and purchase obligations, and including under 'Liquidity and capital resources – Trend information', with regard to production in Upstream, the expected financial impact of refinery turnarounds, expectations regarding petrochemicals margins and the average quarterly charge for Other businesses and corporate, estimated levels of capital expenditure in 2013 and to the end of the decade, estimated amount of divestments, intentions regarding net debt ratio and the expected level of depreciation, depletion and amortization, and the expected level of underlying effective tax rate; and (iv) certain statements in Additional disclosures (pages 161-175) regarding the anticipated timing of trial proceedings, court decisions and potential investigations and civil or criminal actions by US state and/or local governments; 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 receipt of relevant third party and/or government approvals; the timing of bringing new fields onstream; the timing of certain disposals; future levels of industry product supply, demand and pricing, including supply growth in North America; OPEC quota restrictions; PSA effects; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; regulatory or legal actions including the types of enforcement action pursued and the nature of remedies sought; the actions of prosecutors, regulatory authorities and courts; the actions of the Claims Administrator appointed under the Economic and Property Damages Settlement; the actions of all parties to the Gulf of Mexico oil spill-related litigation at various phases of the litigation; exchange rate fluctuations; development and use of new technology; the success or otherwise of partnering; the actions of competitors; the actions of contractors; 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' (pages 38-44). 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.

Business review

BP in more depth

Detailed reporting on activity across the group during a busy year.

Financial review

Selected financial information[a]

					$ million
	2012	2011	2010	2009	2008
Income statement data					
Sales and other operating revenues	**375,580**	375,517	297,107	239,272	361,143
Underlying replacement cost profit (loss) before interest and tax[b]					
By business					
Upstream	**19,419**	25,225	25,073	19,668	37,318
Downstream	**6,447**	6,013	4,883	3,607	3,318
TNK-BP[c]	**3,127**	4,134	2,617	1,948	2,262
Other businesses and corporate	**(1,997)**	(1,656)	(1,316)	(1,833)	(590)
Consolidation adjustment – unrealized profit in inventory	**(576)**	(113)	447	(717)	466
	26,420	33,603	31,704	22,673	42,774
Net favourable (unfavourable) impact of non-operating items and fair value accounting effects[b]					
By business					
Upstream	**3,055**	1,141	3,196	3,184	(1,272)
Downstream	**(3,601)**	(539)	672	(2,864)	858
TNK-BP	**246**	–	–	–	–
Other businesses and corporate	**(798)**	(822)	(200)	(489)	(633)
Gulf of Mexico oil spill response[d]	**(4,995)**	3,800	(40,858)	–	–
	(6,093)	3,580	(37,190)	(169)	(1,047)
Replacement cost profit (loss) before interest and tax[b]					
By business					
Upstream	**22,474**	26,366	28,269	22,852	36,046
Downstream	**2,846**	5,474	5,555	743	4,176
TNK-BP[c]	**3,373**	4,134	2,617	1,948	2,262
Other businesses and corporate	**(2,795)**	(2,478)	(1,516)	(2,322)	(1,223)
Gulf of Mexico oil spill response[d]	**(4,995)**	3,800	(40,858)	–	–
Consolidation adjustment – unrealized profit in inventory	**(576)**	(113)	447	(717)	466
Replacement cost profit (loss) before interest and taxation[b]	**20,327**	37,183	(5,486)	22,504	41,727
Inventory holding gains (losses)[e]	**(594)**	2,634	1,784	3,922	(6,488)
Profit (loss) before interest and taxation	**19,733**	39,817	(3,702)	26,426	35,239
Finance costs and net finance expense/income relating to pensions and other post-retirement benefits	**(924)**	(983)	(1,123)	(1,302)	(956)
Taxation	**(6,993)**	(12,737)	1,501	(8,365)	(12,617)
Profit (loss) for the year	**11,816**	26,097	(3,324)	16,759	21,666
Profit (loss) for the year attributable to BP shareholders	**11,582**	25,700	(3,719)	16,578	21,157
Inventory holding (gains) losses[e], net of tax	**411**	(1,800)	(1,195)	(2,623)	4,436
Replacement cost profit (loss) for the year attributable to BP shareholders[b]	**11,993**	23,900	(4,914)	13,955	25,593
Non-operating items and fair value accounting effects[b], net of tax	**(5,645)**	2,242	(25,436)	(622)	(650)
Underlying replacement cost profit (loss) for the year attributable to BP shareholders[b]	**17,638**	21,658	20,522	14,577	26,243

[a] This information, insofar as it relates to 2012, has been extracted or derived from the audited consolidated financial statements of the BP group presented on pages 177-262. 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.

[b] Replacement cost (RC) profit or loss reflects the replacement cost of supplies and is arrived at by excluding inventory holding gains and losses from profit or loss. RC profit or loss is the measure of profit or loss for each operating segment that is required to be disclosed under International Financial Reporting Standards (IFRS). RC profit or loss for the group is not a recognized GAAP measure. Underlying RC profit or loss is RC profit or loss after adjusting for non-operating items and fair value accounting effects. Underlying RC profit or loss and fair value accounting effects are not recognized GAAP measures. For further information on RC profit or loss, underlying RC profit or loss, non-operating items and fair value accounting effects, see page 37 and Certain definitions on pages 98-99.

[c] BP ceased equity accounting for its share of TNK-BP earnings from 22 October 2012. See TNK-BP on pages 80-81 for further information.

[d] Under IFRS these costs are presented as a reconciling item between the sum of the results of the reportable segments and the group results.

[e] Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies acquired during the year and the cost of sales calculated on the first-in first-out (FIFO) method, after adjusting for any changes in provisions where the net realizable value of the inventory is lower than its cost. BP's management believes it is helpful to disclose this information. An analysis of inventory holding gains and losses by business is shown in Financial statements – Note 6 on page 203 and further information on inventory holding gains and losses is provided on page 98.

Selected financial information – continued

					$ million except per share amounts
	2012	2011	2010	2009	2008
Per ordinary share – cents					
Profit (loss) for the year attributable to BP shareholders					
Basic	**60.86**	135.93	(19.81)	88.49	112.59
Diluted	**60.45**	134.29	(19.81)	87.54	111.56
Replacement cost profit (loss) for the year attributable to BP shareholders	**63.02**	126.41	(26.17)	74.49	136.20
Underlying replacement cost profit for the year attributable to BP shareholders	**92.68**	114.55	109.23	77.81	139.66
Dividends paid per share – cents	**33.00**	28.00	14.00	56.00	55.05
– pence	**20.852**	17.404	8.679	36.417	29.387
Capital expenditure and acquisitions[a]	**24,342**	31,518	23,016	20,309	30,700
Acquisitions and asset exchanges	**200**	11,283	3,406	308	2,514
Organic capital expenditure[b]	**23,088**	19,139	18,218	20,001	21,697
Balance sheet data (at 31 December)					
Total assets	**300,193**	293,068	272,262	235,968	228,238
Net assets	**119,620**	112,482	95,891	102,113	92,109
Share capital	**5,261**	5,224	5,183	5,179	5,176
BP shareholders' equity	**118,414**	111,465	94,987	101,613	91,303
Finance debt due after more than one year	**38,767**	35,169	30,710	25,518	17,464
Net debt to net debt plus equity[c]	**18.7%**	20.5%	21.2%	20.4%	21.4%
Ordinary share data[d]					Shares million
Average number outstanding of 25 cent ordinary shares (undiluted)	**19,028**	18,905	18,786	18,732	18,790
Average number outstanding of 25 cent ordinary shares (diluted)	**19,158**	19,136	18,998	18,936	18,963

[a] Includes asset exchanges. All capital expenditure and acquisitions during the past five years have been financed from cash flow from operations, disposal proceeds and external financing.

[b] Organic capital expenditure excludes acquisitions and asset exchanges, and: in 2012, $1,054 million associated with deepening our US natural gas and North Sea asset bases; in 2011, $1,096 million associated with deepening our US natural gas asset bases; in 2010, $900 million relating to the formation of a partnership with Value Creation Inc. to develop the Terre de Grace oil sands acreage and $492 million for the purchase of additional interests in the Valhall and Hod fields in the North Sea; and, in 2008, $3,667 million in respect of our purchase of all 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 and $2,822 million relating to the formation of an integrated North American oil sands business with Husky Energy Inc.

[c] Net debt and the ratio of net debt to net debt plus equity are not recognized GAAP measures. We believe that these measures provide useful information to investors. Further information on net debt is given in Financial statements – Note 35 on page 234.

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

Profit or loss for the year

Profit attributable to BP shareholders for the year ended 31 December 2012 was $11,582 million. After adjusting for $411 million in respect of inventory holding losses and their associated tax effect, replacement cost (RC) profit attributable to BP shareholders in 2012 was $11,993 million. After further adjusting for a net charge of $5,300 million for non-operating items and adverse fair value accounting effects (relative to management's measure of performance) of $345 million, both net of tax, underlying RC profit attributable to BP shareholders in 2012 was $17,638 million. RC profit or loss for the group, underlying RC profit and fair value accounting effects are non-GAAP measures, see footnote b on page 34 for further information.

Non-operating items in 2012, on a pre-tax basis, mainly related to further charges associated with the Gulf of Mexico oil spill (primarily the cost of the agreement with the US government to settle all federal criminal charges) and impairment charges, partially offset by gains on disposals. More information on non-operating items, and fair value accounting effects, can be found on page 37. See Gulf of Mexico oil spill on pages 59-62 and Financial statements – Note 2 on page 194 for further information on the impact of the Gulf of Mexico oil spill on BP's financial results.

For the year ended 31 December 2011, profit attributable to BP shareholders was $25,700 million, replacement cost profit attributable to BP shareholders in 2011 was $23,900 million and underlying RC profit attributable to BP shareholders in 2011 was $21,658 million. Inventory holding gains and their associated tax effect were $1,800 million in 2011. There was a net post-tax credit for non-operating items of $2,195 million, which included a $3.7 billion pre-tax credit relating to the Gulf of Mexico oil spill, and fair value accounting effects had a favourable impact, net of tax, of $47 million.

Compared with 2011, underlying replacement cost profit in 2012 was impacted by higher upstream costs (driven primarily by sector inflation), lower production and realizations, the absence of equity-accounted earnings from TNK-BP as of 22 October 2012 (when our investment was reclassified as an asset held for sale, as required under IFRS), weak petrochemicals margins and a significant reduction in the supply and trading contribution. These factors were partially offset by an improved refining environment, which we were able to capture as a result of strong refinery operations.

For the year ended 31 December 2010, there was a loss attributable to BP shareholders of $3,719 million, which included inventory holding gains, net of tax, of $1,195 million leading to a replacement cost loss attributable to BP shareholders of $4,914 million. After adjusting for a net charge for non-operating items of $25,449 million and net favourable fair value accounting effects of $13 million, both net of tax, underlying profit attributable to BP shareholders in 2010 was $20,522 million. Non-operating items in 2010 included a pre-tax charge relating to the Gulf of Mexico oil spill of $40.9 billion.

Compared with 2010, in 2011 there were higher realizations, higher earnings from equity-accounted entities, a higher refining margin environment and a stronger supply and trading contribution, partly offset by lower production volumes, rig standby costs in the Gulf of Mexico, higher costs related to turnarounds, higher exploration write-offs, and negative impacts of increased relative sweet crude prices in Europe and Australia, primarily caused by the loss of Libya production and the weather-related power outages in the US.

See Upstream on page 63, Downstream on page 72, TNK-BP on page 80 and Other businesses and corporate on page 82 for further information on segment results.

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 2012 were $1,125 million compared with $1,246 million in 2011 and $1,170 million in 2010.

Net finance income relating to pensions and other post-retirement benefits in 2012 was $201 million compared with $263 million in 2011 and $47 million in 2010. In 2012, compared with 2011, the reduced net income largely reflected lower expected returns on pension assets following reductions in the yield assumptions, mainly for bonds, being applied in 2012 compared to 2011.

In 2013, when we adopt the revised version of IAS 19 'Employee Benefits', we will be required to apply the same expected rate of return on plan assets as we use to discount our pension liabilities. We expect this accounting change to adversely impact our annual earnings by approximately $1 billion on a pre-tax basis, with no impact on cash flow.

Taxation

The charge for corporate taxes in 2012 was $6,993 million, compared with a charge of $12,737 million in 2011 and a credit of $1,501 million in 2010. The effective tax rate was 37% in 2012, 33% in 2011 and 31% in 2010. The group earns income in many countries and, on average, pays taxes at rates higher than the UK statutory rate of 24%. The increase in the effective tax rate in 2012 compared with 2011 primarily reflects the impact of the provision for the settlement with the US government, which is not tax deductible. The increase in the effective tax rate in 2011 compared with 2010 primarily reflected a higher level of income earned in jurisdictions with a higher tax rate.

Acquisitions and disposals

In 2012 there were no significant acquisitions.

Total disposal proceeds received during 2012 were $11.4 billion.

In Upstream, total disposal proceeds of $10.7 billion included $5.55 billion for the disposal of BP's interests in the Marlin hub, Horn Mountain, Holstein, Ram Powell and Diana Hoover fields in the Gulf of Mexico. Proceeds of $1.5 billion were received for the sale of the Canadian natural gas liquids (NGL) business to Plains Midstream Canada ULC, a wholly owned subsidiary of Plains All American Pipeline, L.P. and $1.2 billion for the Hugoton basin assets (including the Jayhawk NGL processing plant and associated producing gas fields in Kansas) to an affiliate of LINN Energy, LLC. The sale of BP's interest in the Jonah and Pinedale upstream operations in Wyoming, also to LINN Energy, LLC generated disposal proceeds of $1.025 billion.

In Downstream, disposal proceeds totalled $0.5 billion, including the sale of our interests in purified terephthalic acid production in Malaysia.

There were no significant disposals during 2012 in Other businesses and corporate.

Prior years' transactions

In 2011, BP acquired from Reliance Industries Limited (Reliance) a 30% interest in each of 21 oil and gas production-sharing agreements operated by Reliance in India for $7.0 billion. We completed the purchase, for $3.6 billion, of 10 exploration and production blocks in Brazil, which was the final part of a $7-billion transaction with Devon Energy that had been announced in March 2010, and our Alternative Energy business acquired the Brazilian sugar and ethanol producer Companhia Nacional de Açúcar e Álcool (CNAA) for $0.7 billion. See Financial statements – Note 3 on page 198 for further details of business combinations.

Total disposal proceeds received during 2011, after the repayment of the disposal deposit relating to Pan American Energy LLC (PAE) (see below), were $2.7 billion.

In Upstream, disposal proceeds included $0.6 billion from the sale of our upstream assets in Pakistan to United Energy Pakistan Limited, a subsidiary of United Energy Group (UEG); $0.5 billion from the sale of half of the 3.29% interest in the Azeri-Chirag-Gunashli (ACG) development in the Caspian Sea, which we had acquired from Devon Energy in 2010, to Azerbaijan (ACG) Limited; and $0.5 billion from the sale of our interests in the Wytch Farm, Wareham, Beacon and Kimmeridge fields to Perenco UK Ltd. In addition, further payments of $1.1 billion were received on completion of the sales of our upstream and certain midstream interests in Venezuela and Vietnam and our oil and gas exploration, production and transportation business in Colombia, for which we had received $2.3 billion in 2010 as deposits. In November 2011, BP received from Bridas Corporation (Bridas) a notice of termination of the agreement for their purchase of BP's 60% interest in PAE. As a result, the deposit of $3.5 billion relating to the sale of PAE, which had been received by BP in 2010, was repaid to Bridas.

In Downstream we made disposals totalling $0.7 billion, which included completion of the divestment of non-strategic pipelines and terminals in the US, announced in 2009, for $0.3 billion and the disposal of our fuels marketing businesses in several African countries for $0.2 billion.

Within Other businesses and corporate, we completed the sale of BP's wholly-owned subsidiary, ARCO Aluminum Inc., to a consortium of Japanese companies for $0.7 billion.

In 2010, BP acquired a major portfolio of deepwater exploration acreage and prospects in the US Gulf of Mexico and an additional interest in the BP-operated ACG developments in the Caspian Sea, Azerbaijan, for $2.9 billion, as part of a $7-billion transaction with Devon Energy. Total disposal proceeds during 2010 were $17 billion, which included $7 billion from the sale of US Permian Basin, Western Canadian gas assets, and Western Desert exploration concessions in Egypt to Apache Corporation (and an existing partner that exercised pre-emption rights), and $6.2 billion of deposits received in advance of disposal transactions expected to complete in 2011. Of these deposits received, $3.5 billion was for the sale of our interest in PAE to Bridas; however, this was subsequently repaid to Bridas at the end of 2011 following the termination of the sale agreement.

The deposits received also included $1 billion for the sale of our upstream and midstream interests in Venezuela and Vietnam to TNK-BP, and $1.3 billion for the sale of our oil and gas exploration, production and transportation business in Colombia to a consortium of Ecopetrol and Talisman.

In Downstream we made disposals totalling $1.8 billion in 2010, which included our French retail fuels and convenience business to Delek Europe; the fuels marketing business in Botswana to Puma Energy; certain non-strategic pipelines and terminals in the US, our interests in ethylene and polyethylene production in Malaysia to Petronas; and our interest in a futures exchange.

Non-operating items

Non-operating items are charges and credits arising in consolidated entities and in TNK-BP that are included in the financial statements and that BP discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers not to be part of underlying business operations and are disclosed in order to enable investors better to understand and evaluate the group's reported financial performance. An analysis of non-operating items is shown in the table below.

			$ million
	2012	2011	2010
Upstream			
Impairment and gain (loss) on sale of businesses and fixed assets	**3,638**	2,131	3,812
Environmental and other provisions	**(48)**	(27)	(54)
Restructuring, integration and rationalization costs	**–**	–	(137)
Fair value gain (loss) on embedded derivatives	**347**	191	(309)
Other[a]	**(748)**	(1,165)	(113)
	3,189	1,130	3,199
Downstream			
Impairment and gain (loss) on sale of businesses and fixed assets	**(2,935)**	(334)	877
Environmental and other provisions	**(172)**	(219)	(98)
Restructuring, integration and rationalization costs	**(32)**	(4)	(97)
Fair value gain (loss) on embedded derivatives	**–**	–	–
Other	**(35)**	(45)	(52)
	(3,174)	(602)	630
TNK-BP[b]			
Impairment and gain (loss) on sale of businesses and fixed assets	**(55)**	–	–
Environmental and other provisions	**(83)**	–	–
Restructuring, integration and rationalization costs	**–**	–	–
Fair value gain (loss) on embedded derivatives	**–**	–	–
Other	**384**	–	–
	246	–	–
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets	**(282)**	275	5
Environmental and other provisions	**(261)**	(220)	(103)
Restructuring, integration and rationalization costs	**(15)**	(39)	(81)
Fair value gain (loss) on embedded derivatives[c]	**–**	(123)	–
Other[d]	**(240)**	(715)	(21)
	(798)	(822)	(200)
Gulf of Mexico oil spill response	**(4,995)**	3,800	(40,858)
Total before interest and taxation	**(5,532)**	3,506	(37,229)
Finance costs[e]	**(19)**	(58)	(77)
Taxation credit (charge)[f]	**251**	(1,253)	11,857
Total after taxation	**(5,300)**	2,195	(25,449)

[a] 2012 included a charge of $370 million relating to onerous gas marketing and trading contracts and $308 million relating to exploration expense associated with our US natural gas assets (2011 $395 million). 2011 included a charge of $700 million associated with the termination of the agreement to sell our 60% interest in Pan American Energy LLC to Bridas Corporation.

[b] Disclosure of non-operating items for TNK-BP began in 2012. Non-operating items for TNK-BP were reported in the group income statement within earnings from associates until 22 October 2012 – after interest and tax. See TNK-BP on pages 80-81 for more information on non-operating items.

[c] Relates to an embedded derivative arising from a financing arrangement.

[d] 2012 included charges of $244 million relating to our exit from the solar business (2011 $717 million).

[e] Finance costs relate to the Gulf of Mexico oil spill. See Financial statements – Note 2 on page 194 for further details.

[f] For the Gulf of Mexico oil spill and certain impairment losses and disposal gains in 2012, tax is based on US statutory tax rates, except for non-deductible items. For dividends received from TNK-BP in December 2012, there is no tax arising. For other items reported by consolidated subsidiaries, tax is calculated using the group's discrete quarterly effective tax rate (adjusted for the items noted above, equity-accounted earnings from 2012 onwards and the deferred tax adjustments relating to changes to the taxation of UK oil and gas production (2011 $683 million and 2012 $256 million)). Non-operating items arising within the equity-accounted earnings of TNK-BP are reported net of tax.

Non-GAAP information on fair value accounting effects

The impacts of fair value accounting effects, relative to management's internal measure of performance, and a reconciliation to GAAP information is also set out below. Further information on fair value accounting effects is provided on page 98.

			$ million
	2012	2011	2010
Upstream			
Unrecognized gains (losses) brought forward from previous period	**(538)**	(527)	(530)
Unrecognized (gains) losses carried forward	**404**	538	527
Favourable (unfavourable) impact relative to management's measure of performance	**(134)**	11	(3)
Downstream[a]			
Unrecognized gains (losses) brought forward from previous period	**74**	137	179
Unrecognized (gains) losses carried forward	**(501)**	(74)	(137)
Favourable (unfavourable) impact relative to management's measure of performance	**(427)**	63	42
	(561)	74	39
Taxation credit (charge)[b]	**216**	(27)	(26)
	(345)	47	13
By region			
Upstream			
US	**(67)**	15	141
Non-US	**(67)**	(4)	(144)
	(134)	11	(3)
Downstream[a]			
US	**(441)**	–	19
Non-US	**14**	63	23
	(427)	63	42

[a] Fair value accounting effects arise solely in the fuels business.

[b] Tax is calculated using the group's discrete quarterly effective tax rate (adjusted for the Gulf of Mexico oil spill, certain impairment losses and disposal gains in 2012, equity-accounted earnings from 2012 onwards and the deferred tax adjustments relating to changes to the taxation of UK oil and gas production (2011 $683 million, 2012 $256 million)).

Reconciliation of non-GAAP information

			$ million
	2012	2011	2010
Upstream			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**22,608**	26,355	28,272
Impact of fair value accounting effects	**(134)**	11	(3)
Replacement cost profit before interest and tax	**22,474**	26,366	28,269
Downstream			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**3,273**	5,411	5,513
Impact of fair value accounting effects	**(427)**	63	42
Replacement cost profit before interest and tax	**2,846**	5,474	5,555
Total group			
Profit (loss) before interest and tax adjusted for fair value accounting effects	**20,294**	39,743	(3,741)
Impact of fair value accounting effects	**(561)**	74	39
Profit (loss) before interest and tax	**19,733**	39,817	(3,702)

Business review: BP in more depth

Risk factors

We urge you to consider carefully the risks described below. The potential impact of the occurrence, or reoccurrence, of any of the risks described below could have a material adverse effect on BP's business, financial position, results of operations, competitive position, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda.

The risks are categorized against the following areas: strategic and commercial; compliance and control; and safety and operational. In addition, we have also set out one further risk for your attention – those resulting from the 2010 Gulf of Mexico oil spill (the Incident).

The Gulf of Mexico oil spill has had and could continue to have a material adverse impact on BP.
While significant charges have been recognized in the income statement since the Incident occurred in 2010, there is significant uncertainty regarding the extent and timing of the remaining costs and liabilities relating to the Incident, the potential changes in applicable regulations and the operating environment that may result from the Incident, the impact of the Incident on our reputation and the resulting possible impact on our licence to operate including our ability to access new opportunities. The amount of claims that become payable by BP, the amount of fines ultimately levied on BP (including any potential determination of BP's negligence or gross negligence), the outcome of litigation, the terms of any further settlements including the amount and timing of any payments thereunder, and any costs arising from any longer-term environmental consequences of the Incident, will also impact upon the ultimate cost for BP. Although the provisions recognized represent the current best estimates of expenditures required to settle certain present obligations that can be reasonably estimated at the end of the reporting period, there are future expenditures for which it is not possible to measure our obligations reliably and the total amounts paid by BP in relation to all obligations relating to the Incident are subject to significant uncertainty. These uncertainties are likely to continue for a significant period, increase the risks to which the group is exposed and may cause our costs to increase. Thus, the Incident has had, and could continue to have, a material adverse impact on the group's business, competitive position, financial performance, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda, particularly in the US. The risks associated with the Incident could also heighten the impact of the other risks to which the group is exposed as further described below.

Strategic and commercial risks

Access and renewal – BP's future hydrocarbon production depends on our ability to renew and reposition our portfolio. Increasing competition for access to investment opportunities, the effects of the Gulf of Mexico oil spill on our reputation and cash flows, and more stringent regulation could result in decreased access to opportunities globally.
Successful execution of our group strategy depends 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 among both national and international oil companies, and heightened political and economic risks in certain countries where significant hydrocarbon basins are located. Lack of material positions could impact our future hydrocarbon production.

Moreover, the Incident has damaged BP's reputation, which may have a long-term impact on the group's ability to access new opportunities, both in the US and elsewhere. Adverse public, political, regulatory and industry sentiment towards BP, and towards oil and gas drilling activities generally, could damage or impair our existing commercial relationships with counterparties, partners and host governments and could impair our access to new investment opportunities, exploration properties, operatorships or other essential commercial arrangements with potential partners and host governments, particularly in the US. In addition, responding to the Incident has placed, and will continue to place, a significant burden on our cash flow over the next several years, which could also impede our ability to invest in new opportunities and deliver long-term growth.

More stringent regulation of the oil and gas industry generally, and of BP's activities specifically, following the Incident, could increase this risk.

Prices and markets – BP's financial performance is subject to the fluctuating prices of crude oil and gas, the volatile prices of refined products and the profitability of our refining and petrochemicals operations, as well as the general macroeconomic outlook.
Oil, gas and product prices and margins can be very volatile, and are subject to international supply and demand. Political developments (including conflict situations) 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 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 cash flow, profit and 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.

Refining profitability can be volatile, with both periodic over-supply and supply tightness in various regional markets, coupled with fluctuations in demand. Sectors of the petrochemicals industry are also subject to fluctuations in supply and demand, with a consequent effect on prices and profitability. 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.

Governments are facing greater pressure on public finances, which may increase their motivation to intervene in the fiscal and regulatory frameworks of the oil and gas industry, including the risk of increased taxation, nationalization and expropriation.

The global financial and economic situation may have a negative impact on third parties with whom we do, or may do, business. In particular, ongoing instability in or a collapse of the eurozone could trigger a new wave of financial crises and push the world back into recession, leading to lower demand and lower oil and gas prices.

Climate change and carbon pricing – climate change and carbon pricing policies could result in higher costs and reduction in future revenue and strategic growth opportunities.
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 – the diverse nature of our operations around the world exposes us to a wide range of political developments and consequent changes to the operating environment, regulatory environment and law.
We have operations, and are seeking new opportunities, in countries where political, economic and social transition is taking place. Some countries have experienced, or may experience in the future, political instability, changes to the regulatory environment, changes in taxation, 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, could limit our ability to pursue new opportunities, could affect the recoverability of our assets and could cause us to incur additional costs. In particular, our investments in the US, Russia, the Middle East region, North Africa, Bolivia, Argentina, Angola, Azerbaijan and other countries could be adversely affected by heightened political and economic environment risks. See pages 6-7 for information on the locations of our major areas of operation and activities.

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 or that we have not satisfactorily addressed all relevant stakeholder concerns in respect of our operations, our reputation and shareholder value could be damaged and development opportunities may be precluded.

Competition – BP's group strategy depends upon continuous innovation and efficiency in a highly competitive market.
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 the terms of access to new opportunities, licence costs and product prices, affects oil products marketing and requires continuous management focus on reducing unit costs and improving efficiency, while ensuring safety and operational risk is not compromised. 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 require, if our innovation lagged the industry, or if we fail to adequately protect our company brands and trade marks. Our competitive position in comparison to our peers could be adversely affected if competitors offer superior terms for access rights or licences, if we fail to control our operating costs or manage our margins, or if we fail to sustain, develop and operate efficiently a high quality portfolio of assets.

Joint ventures and other contractual arrangements – BP may not have full operational control and may have exposure to counterparty credit risk and disruptions to our operations and strategic objectives due to the nature of some of its business relationships.
Many of our major projects and operations are conducted through joint ventures or associates and through contracting and sub-contracting arrangements. These arrangements often involve complex risk allocation, decision-making processes and indemnification arrangements. In certain cases, we may have less control of such activities than we would have if BP had full operational control. Our partners may have economic or business interests or objectives that are inconsistent with, or opposed to, those of BP and may exercise veto rights to block certain key decisions or actions that BP believes are in its or the joint venture's or associate's best interests, or approve such matters without our consent. Additionally, our joint venture partners or associates or contractual counterparties are primarily responsible for the adequacy of the human or technical competencies and capabilities which they bring to bear on the joint project and, in the event these are found to be lacking, our joint-venture partners or associates may not be able to meet their financial or other obligations to their counterparties or to the relevant project, potentially threatening the viability of such projects. Furthermore, should accidents or incidents occur in operations in which BP participates, whether as operator or otherwise, and where it is held that our sub-contractors or joint-venture partners are legally liable to share any aspects of the cost of responding to such incidents, the financial capacity of these third parties may prove inadequate to fully indemnify BP against the costs we incur on behalf of the joint venture or contractual arrangement. Should a key sub-contractor, such as a lessor of drilling rigs, be no longer able to make these assets available to BP, this could result in serious disruption to our operations. Where BP does not have operational control of a venture, BP may nonetheless still be pursued by regulators or claimants in the event of an incident.

Rosneft transaction – BP's failure to complete the agreed transaction with Rosneft, or any future erosion of our relationship with Rosneft, could adversely impact our business, the level of our reserves and our reputation.
On 22 November 2012, BP announced that it had signed definitive and binding agreements in respect of the sale of BP's 50% interest in TNK-BP to Rosneft and BP's investment in Rosneft (the Rosneft transaction). See TNK-BP on pages 80-81. Completion of the Rosneft transaction is subject to certain customary closing conditions, including governmental, regulatory and anti-trust approvals. Failure by BP to complete the Rosneft transaction as contemplated due to the failure to receive required approvals or otherwise could negatively impact our reputation and result in a loss of stakeholder confidence in BP's ability to meet its identified strategic objectives in Russia. In addition, to the extent we fail to maintain a good commercial relationship with Rosneft in the future, or to the extent that as a minority shareholder in Rosneft we are unable in the future to exercise influence over our investment in Rosneft or other growth opportunities in Russia, our business and strategic objectives in Russia and our ability to recognize our share of Rosneft's reserves as contemplated may be adversely impacted.

Investment efficiency – poor investment decisions could negatively impact our business.
Our organic growth is dependent on creating a portfolio of quality options and investing in the best options. Ineffective investment selection and/or subsequent execution could lead to loss of value and higher capital expenditure.

Reserves progression – inability to progress upstream resources in a timely manner could adversely affect our long-term replacement of reserves and negatively impact our business.
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 due to commercial, technical or regulatory reasons or otherwise, we will be unable to sustain long-term replacement of reserves.

Major project delivery – our group plan depends upon successful delivery of major projects, and failure to deliver major projects successfully could adversely affect our financial performance.
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 or production growth and/or any other major programme designed to enhance shareholder value, including maintenance turnaround programmes, could adversely affect our financial performance. Successful project delivery requires, among other things, adequate engineering and other capabilities and therefore successful recruitment and development of staff is central to our plans. See People and capability on page 40.

Digital infrastructure is an important part of maintaining our operations, and a breach of our digital security could result in serious damage to business operations, personal injury, damage to assets, harm to the environment, reputational damage, breaches of regulations, litigation, legal liabilities and reparation costs.
The reliability and security of our digital infrastructure are critical to maintaining the availability of our business applications, including the reliable operation of technology in our various business operations and the collection and processing of financial and operational data, as well as the confidentiality of certain third-party information. A breach of our digital security, either due to intentional actions or due to negligence, could cause serious damage to business operations and, in some circumstances, could result in the loss of data or sensitive information, injury to people, damage to assets, harm to the environment, reputational damage, breaches of regulations, litigation, legal liabilities and reparation costs.

Business continuity and disaster recovery – the group must be able to recover quickly and effectively from any disruption or incident, as failure to do so could adversely affect our business and operations.
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 our business and operations.

Crisis management – crisis management plans are essential to respond effectively to emergencies and to avoid a potentially severe disruption in our business and operations.
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, development and utilization of staff is central to our plans.
Successful recruitment of new staff, employee training, development and continuing enhancement of skills, in particular technical capabilities such as petroleum engineers and scientists, are key to implementing our plans. Inability to develop human capacity and capability, both across the organization and in specific operating locations, could jeopardize performance delivery. The group relies on recruiting and retaining high-quality employees to execute its strategic plans and to operate its business. The reputational damage suffered by the group as a result of the Incident and any consequent adverse impact on our business could affect employee recruitment and retention.

In addition, significant board and management focus continues to be required in responding to matters related to the Incident. Although BP set up the Gulf Coast Restoration Organization to manage the group's long-term response, other key management personnel will need to continue to devote substantial attention to addressing the associated consequences for the group, which may negatively impact our staff's capability to address and respond to other operational matters affecting the group but unrelated to the Incident.

Liquidity, financial capacity and financial, including credit, exposure – failure to operate within our financial framework could impact our ability to operate and result in financial loss. Exchange rate fluctuations can impact our underlying costs and revenues.
The group seeks to maintain a financial framework to ensure that it is able to maintain an appropriate level of liquidity and financial capacity. This framework constrains the level of assessed capital at risk for the purposes of positions taken in financial instruments. Failure to accurately forecast or maintain sufficient liquidity and credit to meet these needs (including a failure to understand and respond to potential liabilities) could impact our ability to operate and result in a financial loss. 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. Trade and other receivables, including overdue receivables, may not be recovered whether an impairment provision has been recognized or not. 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, to maintain our long-term investment programme and to meet our obligations, 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. The group's financial framework may not be sufficient to respond to a substantial and unexpected cash call or funding request, and external events may materially impact the effectiveness of the group's financial framework. In addition, operational challenges could impact the availability of the group's assets, which could adversely affect the group's operating cash flows.

BP's potential liabilities resulting from pending and future claims, lawsuits, settlements and enforcement actions relating to the Gulf of Mexico oil spill, together with the potential cost of implementing remedies sought in the various proceedings, cannot be fully estimated at this time but they have had, and could continue to have, a material adverse impact on the group's financial performance and liquidity. Further potential liabilities may continue to have a material adverse effect on the group's results of operations and financial condition. See Financial statements – Note 43 on page 253 and Legal proceedings on pages 162-171. More stringent regulation of the oil and gas industry arising from the Incident, and of BP's activities specifically, could increase this risk.

Crude oil prices are generally set in US dollars, while sales of refined products may be in a variety of currencies. In addition, a high proportion of our major project development costs are denominated in local currencies, which may be subject to volatile fluctuations against the US dollar. Fluctuations in exchange rates can therefore give rise to foreign exchange exposures, with a consequent impact on underlying costs and revenues. See Prices and markets on page 38.

See Financial statements – Note 26 on page 220 for more information on financial instruments and financial risk factors.

Insurance – BP's insurance strategy means that the group could, from time to time, be exposed to material uninsured losses which could have a material adverse effect on BP's financial condition and results of operations.
In the context of the limited capacity of the insurance market, many significant risks are retained by BP. The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This means that the group could be exposed to material uninsured losses, which could have a material adverse effect on its financial condition and results of operations. In particular, these uninsured costs could arise at a time when BP is facing material costs arising out of some other event which could put pressure on BP's liquidity and cash flows. For example, BP has borne and will continue to bear the entire burden of its share of any property damage, well control, pollution clean-up and third-party liability expenses arising out of the Gulf of Mexico oil spill.

Compliance and control risks

Our settlement with the US Department of Justice and the SEC in respect of federal criminal charges and US securities law violations related to the Gulf of Mexico oil spill may expose us to further penalties, liabilities and private litigation, and may impact our operations and adversely affect our ability to quickly and efficiently access US capital markets.
On 15 November 2012, BP reached an agreement with the US government to resolve all federal criminal and securities claims arising out of the Incident and comprising settlements with the US Department of Justice (DoJ) and the SEC. On 29 January 2013, the US District Court for the Eastern District of Louisiana accepted BP's pleas regarding the federal criminal charges, and sentenced BP in accordance with the criminal plea agreement. BP pleaded guilty to 11 felony counts of Misconduct or Neglect of Ships Officers relating to the loss of 11 lives; one misdemeanour count under the Clean Water Act; one misdemeanour count under the Migratory Bird Treaty Act; and one felony count of obstruction of Congress. Pursuant to that sentence, BP will pay $4 billion, including $1.256 billion in criminal fines, in instalments over a period of five years. The court also ordered, as previously agreed with the US government, that BP serve a term of five years' probation. Pursuant to the terms of the plea agreement, the court also ordered certain equitable relief, including additional actions, enforceable by the court, to further enhance the safety of drilling operations in the Gulf of Mexico. In addition, BP will undertake several initiatives with academia and regulators to develop new technologies related to deepwater drilling safety. The resolution also provides for the appointment of two monitors, both with terms of four years. A process safety monitor will review, evaluate, and provide recommendations for the improvement of BP's process safety and risk management procedures concerning deepwater drilling in the Gulf of Mexico. An ethics monitor will review and provide recommendations for the improvement of BP's code of conduct and its implementation and enforcement. BP has also agreed to hire an independent third-party auditor who will review and report to the probation officer, the DoJ, and BP regarding BP's implementation of key terms of the proposed settlement, including procedures and systems related to safety and environmental management, operational oversight, and oil spill response training and drills. Under the plea agreement, BP has also agreed to co-operate in ongoing criminal actions and investigations, including prosecutions of four former employees who have been separately charged.

Also on 15 November 2012, BP reached a settlement with the SEC to resolve the SEC's Deepwater Horizon-related claims against the company under Sections 10(b) and 13(a) of the Securities Exchange Act of 1934 and the associated rules. Under the SEC settlement, BP has agreed to a civil penalty of $525 million, payable in three instalments over a period of three years, and has consented to the entry of an injunction prohibiting it from violating certain US securities laws and regulations. The SEC settlement was approved by the US District Court for the Eastern District of Louisiana on 10 December 2012. See Legal proceedings on pages 162-171.

On 28 November 2012, the US Environmental Protection Agency (EPA) notified BP that it had temporarily suspended BP p.l.c., BP Exploration & Production Inc. (BPXP) and a number of other BP subsidiaries from participating in new federal contracts. As a result of the temporary suspension, the BP entities listed in the EPA notice are ineligible to receive any US government contracts either through the award of a new contract, or the extension of the term or renewal of an expiring contract. The suspension does not affect existing contracts the company has with the US government, including those relating to current and ongoing drilling and production operations in the Gulf of Mexico.

The charges to which BPXP pleaded guilty included one misdemeanour count under the Clean Water Act which, by operation of law following the court's acceptance of BP's plea, triggers a statutory debarment, also referred to as mandatory debarment, of the BPXP facility where the Clean Water Act violation occurred.

On 1 February 2013, the EPA issued a notice that BPXP was mandatorily debarred at its Houston headquarters. Mandatory debarment prevents a company from entering into new contracts or new leases with the US government that would be performed at the facility where the Clean Water Act violation occurred. A mandatory debarment does not affect any existing contracts or leases a company has with the US government and will remain in place until such time as the debarment is lifted through an agreement with the EPA.

With respect to the entities named in the temporary suspension, the temporary suspension may be maintained or the EPA may elect to issue a notice of proposed discretionary debarment to some or all of the named entities. Like suspension, a discretionary debarment would preclude BP entities listed in the notice from receiving new federal fuel contracts, as well as new oil and gas leases, although existing contracts and leases will continue. Discretionary debarment typically lasts three to five years and may be imposed for a longer period, unless it is resolved through an administrative agreement.

While BP's discussions with the EPA have been taking place in parallel to the court proceedings on the criminal plea, the company's work toward reaching an administrative agreement with the EPA is a separate process, and it may take some time to resolve issues relating to such an agreement. BP's mandatory debarment applies following sentencing and is not an indication of any change in the status of discussions with the EPA. The process for resolving both mandatory and discretionary debarment is essentially the same as for resolving the temporary suspension. BP continues to work with the EPA in preparing an administrative agreement that will resolve suspension and debarment issues.

The DoJ criminal and SEC settlements impose significant compliance and remedial obligations on BP and its directors, officers and employees. Failure to comply with the terms of these settlements could result in further enforcement action by the DoJ and the SEC, expose BP to severe penalties, financial or otherwise, and subject BP to further private litigation, each of which could impact our operations and have a material adverse effect on the group's business. Prolonged suspension or debarment from entering new federal contracts, or further suspension or debarment proceedings against BP and/or its subsidiaries as a result of violations of the terms of the DoJ or SEC settlements or otherwise, could have a material adverse impact on the group's operations in the US.

As a result of the SEC settlement, as of the filing with the SEC of certain registration statements on Form S-8 on 5 February 2013, and for a period of three years thereafter, we will no longer be qualified as a 'well known seasoned issuer' (WKSI) as defined in Rule 405 of the Securities Act of 1933, as amended (Securities Act), and therefore will not be able to take advantage of the benefits available to a WKSI, including engaging in delayed or continuous offerings of securities using an automatic shelf registration statement. In addition, as of the settlement date and for a period of five years thereafter, we are no longer able to utilize certain registration exemptions provided by the Securities Act in connection with certain securities offerings. In addition, we may be denied certain trading authorizations under the rules of the US Commodities Futures Trading Commission, which may prevent us in the future from entering certain routine swap transactions for an indefinite period of time.

Regulatory – BP, and the oil industry in general, face increased regulation in the US and elsewhere that could increase the cost of regulatory compliance and limit our access to new exploration properties.
Due to the Gulf of Mexico oil spill and any remedial provisions contained in or resulting from the DoJ and SEC settlements (see Legal proceedings on pages 162-169), it is likely that there will be more stringent regulation of BP's oil and gas activities in the US and elsewhere, particularly relating to environmental, health and safety controls and oversight of drilling operations, as well as access to new drilling areas. Regulatory or legislative action may impact the industry as a whole and could be directed specifically towards BP. New regulations and legislation, the terms of BP's settlements with US government authorities and future settlements or litigation outcomes related to the Incident, and/or evolving practices could increase the cost of compliance and may require changes to our drilling operations, exploration, development and decommissioning plans, and could impact our ability to capitalize on our assets and limit our access to new exploration properties or operatorships, particularly in the deepwater Gulf of Mexico. In addition, increases in taxes, royalties and other amounts payable to governments or governmental agencies, or restrictions on availability of tax relief, could also be imposed as a response to the Incident.

In addition, the oil industry in general 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, health and safety 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. See pages 51-54 for more information on environmental regulation.

Ethical misconduct and non-compliance – ethical misconduct or breaches of applicable laws by our employees could be damaging to our reputation and shareholder value.
Our code of conduct, which applies to all employees, defines our commitment to integrity, compliance with all applicable legal requirements, diversity, high ethical standards and the behaviours and actions we expect of our businesses and people wherever we operate. Our values are intended to guide the way we and our employees behave and do business. Under the terms of the DoJ settlement (see pages 40-41), an ethics monitor will review and provide recommendations for the improvement of our code of conduct and its implementation and enforcement. Incidents of ethical misconduct, non-compliance with the recommendations of the ethics monitor or non-compliance with applicable laws and regulations, including non-compliance with anti-bribery, anti-corruption and other applicable laws could be damaging to our reputation and shareholder value and could subject us to further regulatory action or penalties under the terms of the DoJ settlement. Multiple events of non-compliance could call into question the integrity of our operations. For example, in our trading businesses, there is the risk that a determined individual could operate as a 'rogue trader', acting outside BP's delegations, controls or code of conduct and in contravention of our values in pursuit of personal objectives that could be to the detriment of BP and its shareholders.

For certain legal proceedings involving the group, see Legal proceedings on pages 162-171. For further information on the risks involved in BP's trading activities, see Treasury and trading activities on page 43.

Liabilities and provisions – BP's potential liabilities resulting from pending and future claims, lawsuits, settlements and enforcement actions relating to the Gulf of Mexico oil spill, together with the potential cost and burdens of implementing remedies sought in the various proceedings, cannot be fully estimated at this time but they have had, and are expected to continue to have, a material adverse impact on the group's business.
Under the Oil Pollution Act of 1990 (OPA 90), BP Exploration & Production Inc. and BP Corporation North America are among the parties financially responsible for the clean-up of the Gulf of Mexico oil spill and for certain economic damages as provided for in OPA 90, as well as certain natural resource damages associated with the spill and certain costs determined by federal and state trustees engaged in a joint assessment of such natural resource damages.

BP and certain of its subsidiaries have also been named as defendants in numerous lawsuits in the US arising out of the Incident, including actions for personal injury and wrongful death, purported class actions for commercial or economic injury, actions for breach of contract, violations of statutes, property and other environmental damage, securities law claims and various other claims. See Legal proceedings on pages 162-169.

BP is subject to a number of investigations related to the Incident by numerous federal and State agencies. See Legal proceedings on pages 162-169. The types of enforcement action pursued and the nature of the remedies sought will depend on the discretion of the prosecutors and regulatory authorities and, in some circumstances, their assessment of BP's culpability, if any, following their investigations. Under the Clean Water Act, any finding of gross negligence for purposes of penalties sought against BP would result in significantly higher fines and penalties than the amounts for which we have provided and would also have a material adverse impact on the group's reputation, would affect our ability to recover costs relating to the Incident from other parties responsible under OPA 90 and could affect the fines and penalties payable by BP with respect to the Incident under enforcement actions outside the Clean Water Act context.

On 3 March 2012, BP reached an agreement (comprising two separate settlement agreements) with the Plaintiffs' Steering Committee (PSC) in the Multi-District Litigation pending in New Orleans (MDL 2179) to resolve the substantial majority of legitimate private economic and property damages claims and medical benefits claims stemming from the Incident. The settlement agreement in respect of economic and property damages claims was approved by the Court on 21 December 2012, and the settlement agreement in respect of medical benefits claims was approved on 11 January 2013. The PSC settlement is uncapped except for economic loss claims related to the Gulf seafood industry. The cost of the PSC settlement is expected to be paid from the $20-billion Deepwater Horizon Oil Spill Trust fund (Trust). As at 31 December 2011, the estimate of items covered by the settlement with the PSC for Individual and Business claims was $7.8 billion. During 2012, BP increased its estimate of the cost of claims administration by $280 million and also increased the estimate by a further $400 million as described below.

Business economic loss claims received by the Deepwater Horizon Court Supervised Settlement Program (DHCSSP) to date are being paid at a significantly higher average amount than previously assumed by BP in formulating the original estimate of the cost. Further, BP's initial estimate of aggregate liability under the settlement agreements was premised on BP's interpretation of certain protocols established in the economic and property damages settlement agreement. As part of its monitoring of payments made by the court-supervised claims processes operated by the DHCSSP for the economic and property damages settlement, BP identified multiple claim determinations that appeared to result from an interpretation of the settlement agreement by that settlement's claims administrator that BP believes was incorrect. This interpretation produced a higher number and value of awards than the interpretation BP assumed in making the initial estimate. Pursuant to the mechanisms in that settlement agreement, the claims administrator sought clarification from the court on this matter and on 30 January 2013, the court initially upheld the claims administrator's interpretation of the agreement.

In its unaudited fourth quarter and full year 2012 results announcement dated 5 February 2013, BP stated that if the initial trend of higher average payments than assumed by BP in its original estimate of the cost continued, then it was likely that BP's estimate of these claims would be increased significantly. Management's initial assessment of the ruling regarding the interpretation of the settlement agreement led to an increase in the estimated cost of the settlement with the PSC of $400 million, bringing the total estimated cost to $8.5 billion. This estimate was based upon management's initial assessment of the ruling's impact on claims already submitted to and processed by the DHCSSP. At that time, BP was seeking reversal of the court's decision in relation to this matter, management concluded that it was not possible to estimate reliably the impact of the interpretation on any future claims not yet received or processed by the DHCSSP.

On 6 February 2013, the court reconsidered and vacated its ruling of 30 January 2013 and stayed the processing of certain types of business economic loss claims. The court lifted the stay on 28 February 2013. On 5 March 2013, the court affirmed the claims administrator's interpretation of the economic and property damages settlement agreement and rejected BP's position as it relates to business economic loss claims. BP strongly disagrees with the decision of 5 March 2013 and the current implementation of the agreement by the claims administrator. BP intends to pursue all available legal options, including rights of appeal, to challenge this ruling. Other business economic loss claims have continued to be paid at a higher average amount than previously assumed by BP in determining its initial estimate of the total cost. Management has continued to analyse the claims in the period since 5 February 2013 to gain a better understanding of whether or not the number and average value of claims received and processed to date are predictive of future claims (and so would allow management to estimate the total cost of the Settlements reliably). Management has concluded based upon this analysis that it is not possible to determine whether the claims experience to date is, or is not, an appropriate basis for determining the total cost. Therefore, given the inherent uncertainty that exists as BP pursues all available legal options to challenge the recent ruling and the higher number of claims received and higher average claims payments than previously assumed by BP, which may or may not continue, management has concluded that no reliable estimate can be made of any business economic loss claims not yet received or processed by the DHCSSP.

Therefore, BP's estimate of the cost of business economic loss claims at 31 December 2012 now includes only the estimated cost of claims already received and processed by the DHCSSP. An amount of $0.8 billion previously provided for future claims not yet received and processed by the DHCSSP has been derecognized, with a corresponding reduction in the reimbursement asset and therefore no net impact on the income statement, as no reliable estimate can be made for this liability. It is therefore disclosed as a contingent liability in Note 43. A provision will be re-established when a reliable estimate can be made of the liability as explained more fully below.

BP's current estimate of the total cost of those elements of the PSC settlement that can be estimated reliably, which excludes any future business economic loss claims not yet received or processed by the DHCSSP, is $7.7 billion.

If BP is successful in its challenge to the court's ruling, the total estimated cost of the settlement agreement will, nevertheless, be significantly higher than the current estimate of $7.7 billion, because business economic loss claims not yet received or processed are not reflected in the current estimate and the average payments per claim determined so far are higher than anticipated. If BP is not successful in its challenge to the court's ruling, a further significant increase to the total estimated cost of the settlement will be required. However, there can be no certainty as to how the dispute will ultimately be resolved or determined. To the extent that there are insufficient funds available in the Trust fund, payments under the PSC settlement will be made by BP directly and charged to the income statement.

As previously disclosed, significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable through the claims process. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported. In addition, there is further uncertainty in relation to interpretations of the claims administrator regarding the protocols under the economic and property damages settlement agreement and judicial interpretation of these protocols, and the outcomes of any further litigation including in relation to potential opt-outs from the settlement or otherwise.

While BP has determined its current best estimate of the cost of those aspects of the settlement with the PSC that can be measured reliably, it is possible that the actual cost could be significantly higher than this estimate due to the uncertainties noted above. In addition, the provision will be re-established for remaining business economic loss claims and the estimate will increase as more information becomes available, the interpretation of the protocols is clarified and the claims process matures, enabling BP to estimate reliably the cost of these claims. See Financial statements – Note 36 on page 235 and Note 43 on page 253 for further information.

The Gulf of Mexico oil spill has damaged BP's reputation. This, combined with other past events in the US (including the 2005 explosion at the Texas City refinery and the 2006 pipeline leaks in Alaska), may lead to an increase in the number of citations and/or the level of fines imposed in relation to any alleged breaches of safety or environmental regulations.

See Legal proceedings on pages 162-169 and Financial statements – Note 2 on page 194.

Reporting – failure to accurately report our data could lead to regulatory action, legal liability and reputational damage.
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.

As of the date of the SEC settlement, 10 December 2012, and for a period of three years thereafter, we are unable to rely on the safe harbor provisions regarding forward-looking statements provided by the regulations issued under the Securities Act, and the Securities Exchange Act of 1934, as amended. Our inability to rely on these safe harbor provisions may expose us to future litigation and liabilities in connection with forward-looking statements in our public disclosures.

Changes in external factors could affect our results of operations and the adequacy of our provisions.
We remain exposed to changes in the external environment, such as new laws and regulations (whether imposed by international treaty or by national or local governments in the jurisdictions in which we operate), changes in tax or royalty regimes, price controls, government actions to cancel or renegotiate contracts, market volatility or other factors. Such factors could reduce our profitability from operations in certain jurisdictions, limit our opportunities for new access, require us to divest or write-down certain assets or affect the adequacy of our provisions for pensions, tax, environmental and legal liabilities. Potential changes to pension or financial market regulation could also impact funding requirements of the group.

Treasury and trading activities – control of these activities depends on our ability to process, manage and monitor a large number of transactions. Failure to do this effectively could lead to business disruption, financial loss, regulatory intervention or damage to our reputation.
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.

Following the Gulf of Mexico oil spill, Moody's Investors Service, Standard and Poor's and Fitch Ratings downgraded the group's long-term credit ratings. Since that time, the group's credit ratings have improved somewhat but are still lower than they were immediately before the Gulf of Mexico oil spill. The impact that a significant operational incident can have on the group's credit ratings, taken together with the reputational consequences of any such incident, the ratings and assessments published by analysts and investors' concerns about the group's costs arising from any such incident, ongoing contingencies, liquidity, financial performance and volatile credit spreads, could increase the group's financing costs and limit the group's access to financing. The group's ability to engage in its trading activities could also be impacted due to counterparty concerns about the group's financial and business risk profile in such circumstances. Such counterparties could require that the group provide collateral or other forms of financial security for its obligations, particularly if the group's credit ratings are downgraded. Certain counterparties for the group's non-trading businesses could also require that the group provide collateral for certain of its contractual obligations, particularly if the group's credit ratings were downgraded below investment grade or where a counterparty had concerns about the group's financial and business risk profile following a significant operational incident. In addition, BP may be unable to make a drawdown under certain of its committed borrowing facilities in the event that we are aware that there are pending or threatened legal, arbitration or administrative proceedings which, if determined adversely, might reasonably be expected to have a material adverse effect on our ability to meet the payment obligations under any of these facilities. Credit rating downgrades could trigger a requirement for the company to review its funding arrangements with the BP pension trustees. Extended constraints on the group's ability to obtain financing and to engage in its trading activities on acceptable terms (or at all) would put pressure on the group's liquidity. In addition, this could occur at a time when cash flows from our business operations would be constrained following a significant operational incident, and the group could be required to reduce planned capital expenditures and/or increase asset disposals in order to provide additional liquidity, as the group did following the Gulf of Mexico oil spill.

Safety and operational risks

The risks inherent in our operations include a number of hazards that, although many may have a low probability of occurrence, can have extremely serious consequences if they do occur, such as the Gulf of Mexico oil spill. The occurrence of any such risks could have a consequent material adverse impact on the group's business, competitive position, cash flows, results of operations, financial position, prospects, liquidity, shareholder returns and/or implementation of the group's strategic goals.

Process safety, personal safety and environmental risks – the nature of our operations exposes us to a wide range of significant health, safety, security and environmental risks, the occurrence of which could result in regulatory action, legal liability and increased costs and damage to our reputation.
The nature of the group's operations exposes us to a wide range of significant health, safety, security and environmental risks. The scope of these risks is influenced by the geographic range, operational diversity and technical complexity of our activities. In addition, in many of our major projects and operations, risk allocation and management is shared with third parties such as contractors, sub-contractors, joint venture partners and associates. See Strategic and commercial risks – Joint ventures and other contractual arrangements on page 39.

There are risks of technical integrity failure as well as risk of natural disasters and other adverse conditions in many of the areas in which we operate, which could lead to loss of containment of hydrocarbons and other hazardous material, as well as the risk of fires, explosions or other incidents.

In addition, inability to provide safe environments for our workforce and the public while at our facilities or premises could lead to injuries or loss of life and could result in regulatory action, legal liability and damage to our reputation.

Our operations are often conducted in difficult or environmentally sensitive locations, in which the consequences of a spill, explosion, fire or other incident could be greater than in other locations. These operations are subject to various environmental and safety laws, regulations and permits and the consequences of failure to comply with these requirements can include remediation obligations, penalties, loss of operating permits and other sanctions. Accordingly, inherent in our operations is the risk that if we fail to abide by environmental and safety and protection standards, such failure could lead to damage to the environment and could result in regulatory action, legal liability, material costs, damage to our reputation or denial of our licence to operate.

BP's group-wide operating management system (OMS) intends to address health, safety, security, environmental and operations risks, and to provide a consistent framework within which the group can analyse the performance of its activities and identify and remediate shortfalls. There can be no assurance that OMS will adequately identify all process safety, personal safety and environmental risk or provide the correct mitigations, or that all operations will be in conformance with OMS at all times.

Security – hostile activities against our staff and activities could cause harm to people and disrupt our operations.
Security threats require continuous oversight and control. Acts of terrorism, piracy, sabotage, cyber-attacks and similar activities directed against our operations and offices, pipelines, transportation or computer systems could cause harm to people and could severely disrupt business and operations. Our business activities could also be severely disrupted by, among other things, conflict, civil strife or political unrest in areas where we operate.

Product quality – failure to meet product quality standards could lead to harm to people and the environment and loss of customers.
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 – these activities require high levels of investment and are subject to natural hazards and other uncertainties. Activities in challenging environments heighten many of the drilling and production risks including those of integrity failures, which could lead to curtailment, delay or cancellation of drilling operations, or inadequate returns from exploration expenditure.
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. Our exploration and production activities are often conducted in extremely challenging environments, which heighten the risks of technical integrity failure and natural disasters discussed above. 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. In addition, exploration expenditure may not yield adequate returns, for example in the case of unproductive wells or discoveries that prove uneconomic to develop. The Gulf of Mexico oil spill illustrates the risks we face in our drilling and production activities.

Transportation – all modes of transportation of hydrocarbons involve inherent and significant risks.
All modes of transportation of hydrocarbons involve inherent risks. An explosion or fire or loss of containment of hydrocarbons or 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 people and the environment and given the high volumes potentially involved.

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 or otherwise subject to US sanctions ('Sanctioned Countries'). These activities continue to be insignificant to the group's financial condition and results of operations.

In July 2012, US President Obama signed Executive Order 13622 ('EO') authorizing the imposition of additional sanctions against persons who engage in certain dealings with Iran, and in August 2012, the US Congress enacted the US Iran Threat Reduction and Syria Human Rights Act of 2012 ('ITRA'). Further, on 3 January 2013, US President Obama signed into law the National Defense Authorization Act for Fiscal Year 2013, containing a subtitle known as the Iran Freedom and Counter-Proliferation Act of 2012 ('IFCPA') that will impose additional sanctions against Iran when its provisions become effective in July 2013. Together, these measures impose additional sanctions against Iran which include new sanctions against persons involved with Iran's energy, shipping and petrochemicals industries, and sanctions against financial institutions that engage in significant transactions with the Iran Central Bank.

Similarly the EU has strengthened its sanctions on Iran. On 23 March 2012 the Council of the European Union extended its existing measures against Iran by promulgating Regulation 267/2012 which included a prohibition on the import, purchase and transport of Iranian-origin crude oil and petroleum products. Further, on 15 October 2012, the EU announced new restrictive measures against Iran and certain Iranian entities, including Naftiran Intertrade Co. Limited, some of which were effective immediately, and some of which were implemented by an amending Regulation (1263/2012) on 22 December 2012, including a prohibition on the import, purchase and transport of Iranian-origin natural gas.

Both the US and the EU have enacted strong sanctions against Syria, including a prohibition on the purchase of Syrian-origin crude and a US prohibition on the provision of services to Syria by US persons. The EU sanctions against Syria include a prohibition on supplying certain equipment used in the production, refining, or liquefaction of petroleum resources as well as restrictions on dealing with the Central Bank of Syria and numerous other Syrian financial institutions.

BP seeks to comply with all applicable laws and regulations of the US, the EU and other countries where BP operates, and monitors its activities with Sanctioned Countries and persons from Sanctioned Countries.

BP has interests in and operates two fields – the North Sea Rhum field and the Azerbaijan Shah Deniz field – and has interests in a gas marketing entity and a gas pipeline entity which, respectively, market and transport Shah Deniz gas (both entities and related assets are located outside Iran), in which Naftiran Intertrade Co. Limited and NICO SPV Limited (collectively, 'NICO') or Iranian Oil Company (UK) Limited ('IOC UK') have interests. Production was suspended at the North Sea Rhum field (in which IOC UK has a 50% interest) in November 2010 and Rhum remains shut-in. The Shah Deniz field, its gas marketing entity and the gas pipeline entity (in which NICO has a 10% or less non-operating interest) continue in operation. The Shah Deniz joint venture and its gas marketing and pipeline entities were excluded from the main operative provisions of the EU Regulations as well as from the application of the new US sanctions, and fall within the exception for certain natural gas projects under Section 603 of ITRA.

BP has no operations in Iran and it is BP's policy that it shall not purchase or ship crude oil or other products of Iranian origin. Participants in non-BP controlled or operated joint ventures may purchase Iranian-origin crude oil or other components as feedstock for facilities located outside the EU and US. It is also BP's policy that BP shall not sell crude oil or other products into Iran, except that small quantities of lubricants are sold to non-Iranian third parties for resale or use in Iran. Further, until January 2010, BP held an equity interest in an Iranian joint venture that blended and marketed automotive lubricants for sale to domestic consumers in Iran. BP sold its equity interest but continues to sell small quantities of automotive lubricants and components and licence relevant trade marks to the current owner. Transactions with Iranian shipping companies have been terminated. BP currently holds a non-controlling interest in a non-BP operated joint venture which sells crude oil to an Indian entity in which NICO holds a minority, non-controlling stake. In 2012, BP distributed certain scrip dividends to BP shareholder Naftiran Intertrade Co. Limited in accordance with applicable UK law in effect at the time of such scrip dividend distributions. In accordance with relevant EU sanctions under EU Regulation 945/2012, BP has withheld scrip dividend distributions to Naftiran Intertrade Co. Limited from October 2012.

BP has become aware that a Canadian university had been using graduate students, some of whom were nationals of Iran, on a research programme funded in part by BP. BP has suspended such programme and made an initial voluntary disclosure to the US Treasury Department's Office of Foreign Assets Control ('OFAC'), and is currently reviewing these activities to determine to what extent, if any, the activities may have violated OFAC Regulations.

In addition, BP has become aware that in 2010, as consideration for certain auditing services, BP effected a transfer of funds to a local Iranian consulting firm which may have been in violation of relevant EU notification requirements. BP is reviewing this funds transfer to determine to what extent, if any, BP may have violated relevant EU regulations.

Following the imposition in 2011 of further US and EU sanctions against Syria, BP terminated all sales of crude oil and petroleum products into Syria, though BP continues to supply aviation fuel to non-governmental Syrian resellers outside of Syria.

BP sells lubricants in Cuba through a 50:50 joint venture and trades in small quantities of lubricants. BP sold small quantities of lubricants to third parties that were resold in Sudan; BP has terminated these sales. In the first quarter of 2013, BP sold a small quantity of lubricants to a third-party drilling company for use in Myanmar.

BP has equity interests in non-operated joint ventures with air fuel sellers, resellers, and fuel delivery services around the world. From time to time, the joint venture operator may sell or deliver fuel to airlines from Sanctioned Countries or flights to Sanctioned Countries without BP's knowledge or consent. BP has registered and paid required fees for patents and trade marks in Sanctioned Countries.

Disclosure pursuant to Section 219 of ITRA

To our knowledge, none of BP's activities, transactions or dealings are required to be disclosed pursuant to ITRA Section 219, with the following possible exceptions:

The Rhum field ('Rhum'), located in the UK sector of the North Sea, is operated by BP Exploration Operating Company Limited ('BPEOC'), a non-US subsidiary of BP. Rhum is owned under a 50:50 unincorporated joint venture between BPEOC and Iranian Oil Company (U.K.) Limited ('IOC'). The Rhum joint venture was originally formed in 1974. During the period of production from Rhum, the Rhum joint venture supplied natural gas and certain associated liquids to the UK. On 16 November 2010, production from Rhum was suspended in response to relevant EU sanctions. Rhum remains shut-in. During the year ended 31 December 2012, BP recorded gross revenues of £7,329.49 related to Rhum due to changes in prices related to hydrocarbon stock. These changes in prices were non-cash transactions that were recorded as revenue in accordance with BP accounting policy. BP had no net profits related to Rhum during the year ended 31 December 2012, recording an overall loss. BP currently intends to continue to hold its ownership stake in the Rhum joint venture, and to meet any applicable obligations in respect of safety and maintenance of the facilities related to the Rhum field.

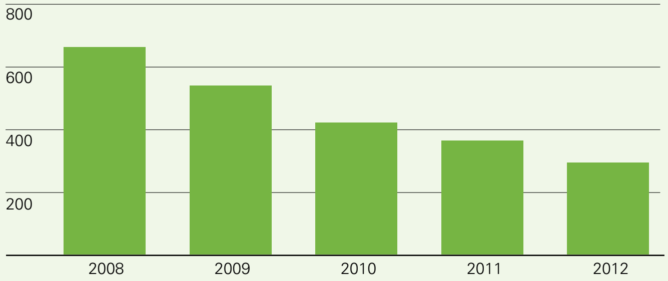
BP distributed dividends in the form of new ordinary shares in accordance with BP's Scrip Dividend Programme to Naftiran Intertrade Co. Limited in March, June and September 2012 as part of BP's dividend distributions to shareholders during those periods. Such scrip dividends were distributed in accordance with applicable UK law in effect during such periods. BP subsequently declared and distributed a dividend to shareholders in December 2012, but a scrip alternative was not distributed to Naftiran Intertrade Co. Limited in accordance with relevant EU sanctions under EU Regulation 945/2012 which took effect in October 2012. As at 1 March 2013, Naftiran Intertrade Co. Limited is the registered owner of ordinary shares in BP amounting to less than 0.15% of BP's total outstanding ordinary shares. BP intends to withhold or to procure the withholding of distribution of any form of dividends to Naftiran Intertrade Co. Limited until such time as applicable laws or regulations permit such distribution.

Safety

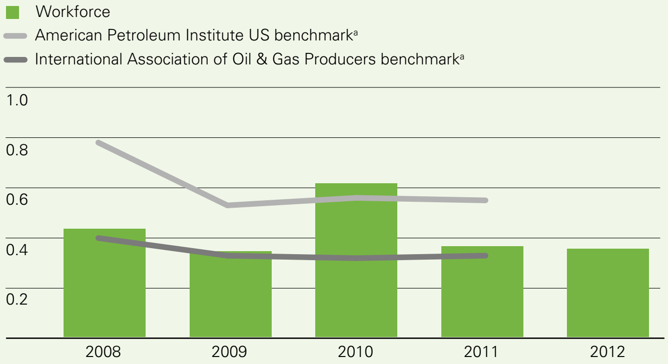
We operate in a high-hazard industry so safety is our top priority. We continue working to embed safety and operational risk management into the heart of the company.

- Our operating management system (OMS) serves as our group-wide framework designed to drive a rigorous and systematic approach to safety, risk management and operational integrity across the group.
- We continue to make progress on all of the remaining recommendations from the Bly Report. As of December 2012, the total number of completed recommendations was 14 out of 26.
- We are focusing on developing deeper, longer-term relationships with selected contractors, identifying potentially higher-risk contracts across the group and bringing a higher level of oversight to these contracts as a priority.

Loss of primary containment
(number of incidents)



Recordable injury frequency
(per 200,000 hours worked)



	2008	2009	2010	2011	2012
Employees					
	0.35	0.23	0.25	0.31	0.26
Contractors					
	0.50	0.43	0.84	0.41	0.43

[a] API and OGP 2012 data reports not available until May.

In 2012 BP reported four workforce fatalities: a road-related fatality in Scotland; a fall from a roof in India; an incident at a compressor station in the US; and a tractor accident in our biofuels business in Brazil. Additionally, the armed attack on our joint venture gas facility in Algeria in January 2013 resulted in four BP fatalities. We deeply regret the loss of these lives.

Managing safety

We are delivering a programme of action to continuously improve safety and risk management across BP. Our approach to safety and risk management is informed by our experience, including what we have learned from the Deepwater Horizon oil spill in 2010 and the Texas City refinery explosion in 2005, operations audits, annual risk reviews, other incident investigations and from industry practice of sharing experience. Three objectives guide our efforts:

- To promote deep capability and a safe operating culture across all levels of BP.
- To embed OMS as the way BP operates.
- To support self-verification and independent assurance that confirms our conduct of operating.

A dedicated function

We established a new safety and operational risk (S&OR) function in early 2011. Our S&OR function supports the business line in delivering safe, reliable and compliant operations across the group's operated business. S&OR:

- Sets clear requirements.
- Maintains an independent view of operating risk.
- Provides deep technical support to the operating businesses.
- Intervenes and escalates as appropriate to cause corrective action.

In 2012 S&OR was led by Mark Bly, the executive vice president who led BP's investigation into the Deepwater Horizon incident. Mark Bly stepped down from his position as executive vice president of safety and operational risk in February 2013 and has been replaced by Bob Fryar who will continue to report directly to the group chief executive.

S&OR consists of a central team and teams deployed in BP's businesses. All teams report to the group chief executive via the head of S&OR, independently of the business line. S&OR includes some of BP's top engineers and safety specialists, several of whom have experience in other industries where major hazards have to be managed, including the military, nuclear energy and space exploration.

The central team serves as the custodian of group-wide safety and operational risk requirements, and runs S&OR audit and capability programmes, with the support of a substantial dedicated audit team.

Our deployed S&OR staff work with our operating businesses – ranging from upstream oil and gas development and production to refineries, petrochemicals plants and retail networks. They help the businesses apply our standards to their operations and help provide assurance to the group as to the management of operational risks, business by business.

Operating businesses remain accountable for delivering safe, reliable and compliant operations with S&OR setting requirements and acting to provide independent advice, scrutiny, challenge and, if needed, intervention.

Governance

BP reviews risks at all levels of the organization, with our S&OR function providing an expert view on safety and operational risks that is independent of the business that remains responsible for management of the risks. While operating line managers are responsible for identifying and managing risks, we place strong emphasis on checks and balances, including both enhanced self-verification by individual BP operations – such as drilling rigs or refineries – and independent assurance by the S&OR function.

Each business segment or function has a safety and operational risk committee, chaired by the segment or function head, to manage safety and risk in their respective areas of the business. The group operations risk committee (GORC) reviews company safety and risk management across the company.

The board's safety, ethics and environment assurance committee (SEEAC) receives updates from the group chief executive and the head of S&OR on management plans associated with the highest priority risks as part of its update on the GORC's work. GORC also provides the SEEAC with updates on BP's process and personal safety performance, and the monitoring of major incidents and near misses across the group. Where appropriate other senior managers attend to provide briefings on safety, environmental and operational integrity in their areas of responsibility. The SEEAC also receives information from external sources, including Carl Sandlin, who was appointed in 2012 to provide oversight and assurance including regarding the implementation of the recommendations of BP's investigation into the Deepwater Horizon accident. See Corporate governance report on pages 101-126 for further information on the activities of the board's committees, including the SEEAC and the Gulf of Mexico committee.

In May 2012 Duane Wilson's five-year board appointment as independent expert to provide an independent objective assessment of BP's progress in implementing the recommendations of the BP US Refineries Independent Safety Review Panel came to an end. Following the end of his term, the SEEAC appointed him as process safety expert and assigned him to work, in a global capacity, with the Downstream business.

Operating management system

BP's OMS is a group-wide framework designed to provide a basis for managing our operations in a systematic way. OMS integrates BP requirements on health, safety, security, environment, social responsibility and operational reliability, as well as related issues such as maintenance, contractor management and organizational learning, into a common management system. Our OMS evolves over time, for example by amending mandatory practices to reflect implementation experience as well as lessons learned from incident investigations, audits and risk assessments.

Integrated into the OMS are guiding principles and requirements for safe, reliable and compliant operations. Each operating unit has an OMS which describes how it addresses specific operating risks and delivers its operating activities. Business needs, applicable legal and regulatory requirements and group-wide BP requirements are translated into practical plans to reduce risk and deliver strong, sustainable performance.

Conformance and continuous improvement

Our OMS was introduced in 2008. The application of a comprehensive management system such as OMS across a global company is an ongoing process. OMS defines the process for BP operations to apply and conform to required standards and practices on an ongoing basis – including defined time periods for doing so – as well as to continuously improve their operational performance. All of our operations, with the exception of those recently acquired, are now applying our OMS to govern their BP operations and are working to achieve full conformance to standards and practices required by OMS through the performance improvement cycle. Recently acquired businesses are working to transition to OMS. See page 99 for information about joint ventures.

OMS is a dynamic system. Periodically, after an initial assessment as part of the annual performance improvement cycle, our operations are required to conduct a fresh assessment to develop an updated prioritized plan in respect of any existing gaps or new gaps that may have been identified. These actions form an integral part of each operation's multi-year and annual planning cycle. Where appropriate, actions are aggregated to provide common solutions. S&OR reviews how these assessments are undertaken.

Capability development

BP strives to equip its staff with the skills needed to apply OMS and its associated processes and practices. For example, in addition to a dedicated programme to assess the technical well control competencies of BP's well site leaders, we have been working to identify safety-critical roles and the associated technical and leadership competencies to do them. We are also strengthening capability and competence by consolidating and standardizing our competence management programme. Our approach is being tested in a number of job categories, such as offshore installation managers and well site leaders.

We continue to provide training programmes for our operations personnel at all levels. This training includes our operations academy programmes for senior management, delivered in partnership with the Massachusetts Institute of Technology, US; specialized operational and technical management programmes, for example, courses in engineering and project management at the University of Manchester, UK; and process safety and management training for our front-line leaders, delivered under our operating essentials programme. Since 2008 we have been running operating essentials modules and in 2012 over 6,000 modules were delivered to managers, supervisors and technicians across the BP group. Both non-executive and senior management team members addressed operations academy participants during sessions in 2012. We also offer a substantial programme of eLearning modules.

Crisis management

Crisis management planning is essential to respond effectively to emergencies and to avoid a potentially severe disruption in our business and operations. In 2012 we issued new group-wide OMS practices for both crisis management and oil-spill preparedness and response, which are replacing the interim practices put in place following the Deepwater Horizon accident. All BP businesses and functions are required to achieve conformance within a defined time period.

See Environmental and social responsibility on pages 51-54 for information on BP's approach to oil spill preparedness and response.

Safer drilling

BP has worked to centralize and standardize our approach to drilling practices and oversight of projects with the establishment of the global wells organization (GWO) and the global projects organization in 2011. The GWO now employs more than 2,000 people, bringing functional wells expertise into a single organization with common global standards. The GWO works with our safety and operational risk function with a view to continuously reducing risk in drilling and so reduce the likelihood of an oil spill or incident occurring. BP has already established requirements and standards for Gulf of Mexico drilling that exceed regulatory requirements.

Following the settlement with the US government of all federal criminal claims related to the Gulf of Mexico, BP has agreed to appoint a process safety monitor in the US for a term of four years. The monitor will review, evaluate and provide recommendations for the improvement of BP's process safety and risk management procedures concerning deepwater drilling in the Gulf of Mexico. Additionally, an independent third-party auditor will review and report on BP's implementation of key terms of the agreement, including procedures and systems related to safety and environmental management, operational oversight, and oil spill response training and drills. For more information on this agreement with the US government, see Legal proceedings on pages 162-169.

Building capability

BP is committed to establishing a global wells institute and has invested in state-of-the art simulator facilities to support practical learning and testing. The institute aims to build and sustain enhanced capability within the GWO by developing the skills to deliver safe and compliant wells that will align with our broader people processes, such as performance development plans and performance appraisals, contractor strategy and ways of working.

Competence testing is an important part of assuring safe operations. In a competence testing programme in the GWO, 532 well site leaders have been assessed on a risk-prioritized basis. Remediation activities have been carried out where areas for improvement have been identified.

We are also engaged in targeted recruitment to support critical work areas. One of these has been the cementing of wells – a key issue as identified in the investigation reports into the Deepwater Horizon accident. For this reason, we are enhancing oversight of cementing services. We have recruited additional expertise into the company and now have 21 cementing specialists.

The Bly Report – implementing the recommendations

The Bly Report concluded that no single cause was responsible for the accident. The investigation instead found that a complex, inter-linked series of mechanical failures, human judgements, engineering design, operational implementation and team interfaces, involving several companies including BP, contributed to the accident.

The Bly Report made 26 recommendations that were specific to drilling. We accepted all of the recommendations and are working to implement them across our drilling operations worldwide. The recommendations include measures to improve contractor management, as well as to strengthen design and assurance on blowout preventers (BOPs), well control, pressure-testing for well integrity, emergency systems, cement testing, rig audit, verification and personnel competence.

Implementing the 26 recommendations across the group requires detailed work and many activities – from creating new practices and guidance, training and testing identified staff, changing requirements and expectations of our contractors, and establishing verification processes.

A project of this scale takes time. Implementing these recommendations across all BP-operated drilling activity across the world is an enormous undertaking involving a programme team of around 85 people, consisting of a central team based in Houston and others embedded in BP's businesses. We are working to assure that all actions are delivered to a high standard across all of our well operations, and are independently verified by our S&OR audit or internal audit function.

We have estimated and communicated delivery timelines for each of the recommendations and will continue to provide periodic updates of our progress. These timelines are based on existing facts and circumstances and can shift due to complexity, resource availability and evolving regulatory requirements.

At the end of 2012, 14 of the Bly Report recommendations had been completed. We continue to make progress on all of the remaining recommendations largely in line with our planned schedule. Progress is tracked quarterly by executive management. We also regularly update investors. See *bp.com/internalinvestigation* for the full report and periodic updates on progress.

Independent advice

In June 2012 the BP board appointed Carl Sandlin to provide SEEAC with an objective and independent assessment of BP's global progress in implementing the 26 Bly Report recommendations and on process safety. Carl Sandlin will also on occasion be asked to provide his views to the board on other matters related to, but not specifically within the scope of the Bly Report recommendations, for example, his views on organizational effectiveness or culture of the GWO and process safety observations in the upstream. He has direct access to the chair of SEEAC and will report to the committee in person at least twice a year. See *BP Sustainability Review 2012* for more information on Carl Sandlin's activities.

Delivering enhanced processes and practices

Eight interim actions were issued to our operating regions immediately following the publication of the Bly Report. Seven of those actions have now been incorporated into engineering technical practices or other documents being developed as part of the work towards completing the 26 recommendations. The final interim action is scheduled to be incorporated into a new practice in early 2013.

During 2012, as we continued to work towards delivering the recommendations, we developed or refreshed key operating practices and engineering standards on:

- Cementing or zonal isolation: we have issued new mandatory requirements and nine associated guides covering cementing activities. As of December 2012, 711 technical professionals in BP have now undergone training on the revised practices. We have also strengthened the technical approval process for some cementing operations. Systematic input into the well design workflow now requires both the regional and global BP specialist to agree on the basis of design for complex zonal isolation activities.
- Integrating process safety concepts into management of wells: we have produced a technical practice specifying minimum requirements for well barrier management – managing the movement of fluids and gas within the well – throughout the life cycle of the well. Implementation of this practice has commenced with two-day workshops training 624 people as of December 2012.
- Well casing design: we have updated our design manual for well casing and inner tubing to include new requirements for pressure tests and revised technical practices. A one-day training workshop on this revised practice has been developed for BP professionals and 247 people have been trained as of December 2012.
- BOP stacks: we have issued a revised technical practice on well control, defining and documenting our requirements for subsea BOP configurations. We require two sets of blind shear rams and a casing shear ram for all subsea BOPs used on dynamically positioned rigs in deep water. This exceeds regulatory requirements. We also require that third-party verification is carried out on the testing and maintenance of subsea BOPs in accordance with industry recommended practice, and that remotely operated vehicles capable of operating these BOPs are available in an emergency.
- Rig intake and start-up operating procedure: we have continued the rig audit process enhanced in 2011. We have also conducted detailed hazard and operability reviews for key fluid handling systems on all offshore rigs in the BP fleet. All drilling rigs joining the BP fleet are subject to an independent S&OR audit and readiness to operate is verified with a detailed go/no-go process assured by S&OR. This includes a checklist that, among other things, assists in assessing that the rig conforms to BP practices and industry standards, that it has the necessary technical specification, and that the actions required for start-up are completed. All rigs are also subject to subsequent periodic rig audits.

BP is in the process of issuing the above guides and implementing the above practices across all our operating regions. Practices are implemented through training workshops and accompanying training materials, gap assessments, and requirements for reaching conformance. We continue to progress the remaining recommendations of the Bly Report.

External investigations

There have also been a number of external investigations into the Gulf of Mexico oil spill, including those of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (*oilspillcommission.gov*) and the joint investigation team of the Bureau of Ocean Energy Management, Regulation and Enforcement and the US Coast Guard (*boemre.gov/ooc/press/2011/press0914.htm*). Additionally, the US National Academy of Engineering undertook an independent study. All of these reports were consistent with the general conclusion that the accident resulted from multiple causes and was due to the actions of multiple parties. We are committed to understanding the causes, impacts and implications of the Deepwater Horizon incident and to learn and act on lessons from it. As part of this commitment, BP is reviewing the recommendations from government and industry reports.

Sharing lessons learned

We are committed to sharing what we have learned globally to advance the capabilities and practices that enhance safety in our company and the deepwater industry and help to prevent an accident of this magnitude from happening again. We have conducted more than 200 briefings in nearly 30 countries over the past two years to share lessons learned. Other examples of our collaboration include:

- Participating in the International Association of Oil & Gas Producers' Well Expert Committee that is working to prevent well control incidents by improving well engineering design and well operations management.
- Providing equipment and expertise developed during the Deepwater Horizon accident response to the Marine Well Containment Company to help industry meet regulatory requirements for drilling in the Gulf of Mexico.
- Participating in the Subsea Well Response Project to enhance the industry's global well capping capabilities – resulting in a collaboration with Oil Spill Response Limited to build four well cap systems and two dispersant application equipment packages due to be positioned in Europe, Africa, Asia and South America in 2013.
- Filing patent applications in the US and elsewhere to cover about 30 technical innovations related to well capping and containment work, with the aim of ensuring the capping and containment technology we have developed will be open for access and further development for the benefit of the industry.
- Implementing a technology licence agreement with Petróleos Mexicanos (PEMEX) that will share BP capping system technology and know-how with the national oil company of Mexico.
- Participating in the 19 sub-committees of the IPIECA/International Oil and Gas Producers Association, Joint Industry Project on Oil Spill Response, focused on developing recommendations for effective and fit-for-purpose oil spill response preparedness and capability.
- Establishing the Center for Offshore Safety with the American Petroleum Institute with a mission to promote the highest level of safety in the deepwater Gulf of Mexico.

Safety in the Downstream business

In our hydrocarbon facilities across the Downstream business we focus on the safe storage, handling and processing of hydrocarbons via systematic management of associated operating risks. In seeking to manage these risks, BP takes measures to:

- Prevent loss of hydrocarbon containment through well-designed, maintained and operated equipment.
- Reduce the likelihood of any hydrocarbon releases and the possibility of ignition that may occur by controlling ignition sources.
- Provide safe locations, emergency procedures and other mitigation measures in the event of a release, fire or explosion.

Senior downstream leaders, led by the segment chief executive, participate in the segment operations risk committee, which provides leadership and expectations on the management of operations. Quarterly, this committee also reviews safety and operations performance indicators. All of our businesses use a set of common leading and lagging safety metrics that are intended to monitor performance and help identify opportunities for improvement.

BP continues to implement the BP US Refineries Independent Safety Review Panel recommendations as part of ongoing process safety management.

Risk management

Hazard identification and risk management are key components of our OMS and are fundamental to the success of safely managing hydrocarbons. Over the past two years, our Downstream business has implemented a risk management programme under OMS that focuses on identification, assessment, response and action to manage safety and operational risk combined with monitoring and review of identified and newly emerging risks.

Management plans for the Downstream businesses' high-consequence, low-probability risks are reviewed annually by the segment chief executive and the chief operating officers.

Some examples of specific risk reduction work across our refining and petrochemicals portfolio in 2012 include:

- Installation of additional safety instrumentation and equipment to reduce the likelihood of identified risks occurring.
- Continuing work to improve the safety of site occupied buildings. We have a major programme under way to install safety shelters for personnel; to move people further away from hydrocarbon-containing equipment; and to reduce the number of vehicles onsite. For example, during 2012 a building-hardening programme was completed at our Toledo refinery, and at our Bulwer refinery we constructed new offices to move employees away from higher risk processing areas. The business also continues to train and drill personnel to respond to emergencies.
- Work to reduce explosion and toxic risks through inventory reduction by, for example, reducing ethylene and propylene refrigerants in our petrochemical plants and by eliminating or reducing the use of ammonia across the refining portfolio.

Where similar risks have been identified across multiple facilities, new guidance for gasoline storage, tanker loading and buildings were developed and issued to drive consistent risk mitigation efforts across the segment.

Capability development

Each facility has experienced and trained operational staff and a system for assessing their competency. We are developing a consistent competency framework that standardizes this assessment process for safety-critical roles supported by and in conjunction with S&OR direction and expertise.

To support the competency development plan for operations personnel, our refineries and chemical manufacturing plants are in the process of installing high fidelity process simulators for selected process units. These will be used to train operators via simulations to respond to low-probability, high-consequence scenarios, similar to methods used with airline pilots.

Measurement, evaluation and corrective action

The oversight of the management of hydrocarbons across our operations is supported by our S&OR function. S&OR personnel work with our operating businesses to provide independent perspectives on the quality of our operations and the management of risks.

A quarterly assurance process enables S&OR to provide an ongoing independent view of OMS conformance by the sites. Each site is assessed on its OMS self-verification processes, the strength of existing risk mitigations and progress on risk reduction plans. Periodic S&OR audits against OMS requirements also provide valuable insights and result in actions to close any identified findings.

Lessons learned from incidents and near-misses are important for identifying ways to improve safety practices. In 2012 we issued a number of briefings and alerts on lessons learned from incidents and near-misses and we require our sites to provide assurance that similar risks have been assessed and appropriate corrective actions undertaken.

New process safety expert for our Downstream business

Duane Wilson's five-year board appointment as independent expert to provide an independent objective assessment of BP's progress in implementing the recommendations of the BP US Refineries Independent Safety Review Panel came to an end in May 2012. Recognizing the extensive experience he has acquired during his years as independent expert and following the end of his term, SEEAC appointed him as process safety expert and assigned him to work, in a global capacity, with the Downstream business.

In this new role, he is providing an independent perspective on the progress that BP's fuels and petrochemicals businesses are making globally toward becoming industry leaders in process safety performance. Specifically, Duane Wilson is focusing and reporting to the SEEAC on three topics:

- Downstream's prioritization of the agenda to become an industry leader in process safety.
- Downstream's progress in embedding BP's OMS – including process safety risk assessment processes, process safety culture and interpretation of trends in process safety performance.
- The effectiveness of the Downstream safety and operational risk function's agenda.

Duane Wilson continues to have frequent and direct access not only to the board, but also to BP employees from the most senior executives down to the shop floor. He visits facilities, conducts interviews and reviews relevant documents, such as audit and incident reports, to fulfil his duties. Additionally, he is an ex officio member of the Downstream segment operations risk committee and regularly attends its meetings with the senior executives of the business. His contract is for a two-year term ending in May 2014, and may be renewed for up to an additional two years on mutual agreement.

Safety performance

Workforce fatalities

In 2012 BP reported four workforce fatalities: a road related fatality in Scotland; a fall from a roof in India; an incident at a compressor station in the US; and a tractor accident in our biofuels business in Brazil. Additionally, the armed attack on our joint venture gas facility in Algeria in January 2013 resulted in four BP fatalities. We deeply regret the loss of these lives.

Oil spills and other loss of primary containment

We monitor the integrity of our assets used to produce, process and transport oil and other hydrocarbons with the aim of preventing the loss of material from its primary containment.

Accordingly, we track loss of primary containment as a metric, which includes unplanned or uncontrolled releases from a tank, vessel, pipe, rail car or equipment used for containment or transfer of materials within our operational boundary, excluding non-hazardous releases such as water.

The US government and third parties have announced various estimates of the flow rate or total volume of oil spilled from the Deepwater Horizon incident. The multi-district litigation pending in New Orleans will address the amount of oil spilled. See Financial statements – Note 36 on page 235 for information about the volume used to determine the estimated liabilities.

Loss of primary containment and oil spills (excluding Deepwater Horizon oil spill in respect of 2010 volume)

	2012	2011	2010
Loss of primary containment – number of all incidents[a]	**292**	361	418
Loss of primary containment – number of oil spills[b]	**204**	228	261
Number of oil spills to land and water	**102**	102	142
Volume of oil spilled (thousand litres)	**801**	556	1,719
Volume of oil unrecovered (thousand litres)	**320**	281	758

[a] Does not include either small or non-hazardous releases.
[b] Number of spills greater than or equal to one barrel (159 litres, 42 US gallons).

Process safety

We monitor the number of process safety events occurring across our operations using the American Petroleum Institute (API) RP-754 standard. Introduced in 2010 it sets out process safety indicators, organized into different tiers and is used as the basis for our internal and external process safety reporting. API tier 1 process safety events are the loss of primary containment from a process of greatest consequence – causing harm to a member of the workforce or costly damage to equipment, or exceeding defined quantities. API tier 2 process safety events are loss of primary containment, from a process, of lesser consequence. Forty-three tier 1 process safety events were reported in BP in 2012, compared with 74 in 2011. This is our first year reporting API tier 2 safety events externally.

Personal safety

BP reports publicly on its personal safety performance according to standard industry metrics.

Personal safety performance

	2012	2011	2010
Recordable injury frequency (group) – incidents per 200,000 hours worked	**0.35**	0.36	0.61
Days away from work case frequency[a] (group) – incidents per 200,000 hours worked	**0.076**	0.090	0.193

[a] Incidents that resulted in an injury where a person is unable to work for a day (shift) or more.

Working with partners and contractors

BP, like our industry peers, rarely works in isolation – we need to work with suppliers, contractors and partners to carry out our operations. In 2012, 55% of the 402 million hours worked by BP were carried out by contractors.

Our ability to be a safe and responsible operator depends in part on the conduct of our suppliers, contractors and partners. We address this in a variety of ways, from training and dialogue to requiring adherence to operational standards through legally binding agreements.

Our OMS is a group-wide framework designed to provide business-specific requirements and practices, including for working with contractors and our operations are obliged to plan and execute actions to reach conformance with OMS on contractor management. OMS is also designed to drive continuous improvement, including how BP businesses continue to work towards full conformance with the elements relevant to working with contractors.

In 2012 we prepared guidance for conformance with OMS, where it relates to working with contractors, in order to support the accountable line organizations. We intend to field test this in 2013.

We expect our contractors to comply with legal requirements and to operate consistently with the principles of our code of conduct when they work on our behalf. The objective is to provide assurance that goods, equipment and services provided by third parties meet contractual and BP requirements and that there is a consistent, shared understanding of responsibilities.

Following the Deepwater Horizon incident, we undertook an in-depth review of contractor management practices, with the aim of documenting and learning from the latest proven practices throughout BP and across a number of sectors and industries that use contractors in potentially high-consequence activities. The review confirmed to us the value of building long-term relationships with a limited number of contractors, supported by shared structures and common processes.

Initially our work has focused on contracts in our upstream supply chain involving potentially high-consequence activities. In 2012 we built on this work to identify contracts involving potentially higher-consequence activities across the group and bringing a consistent level of oversight to the management of these contracts as a priority. In our global projects organization, we have put in place global agreements with seven suppliers for plant inspection and surveillance services, covering the work previously undertaken by more than 60 suppliers.

The review also highlighted the importance of clearly defined responsibilities and decision rights at every stage of each process – including training, monitoring and auditing – as well as rigorous qualification of suppliers, including their demonstration of the competency of key personnel. In 2012 we focused, including through our OMS, on practical assistance to operational line management to build competence in this area.

In 2013, we plan to continue our work on the management of contractors through our OMS framework and actions related to additional supplier audits, competence testing and other programmes.

Our partners in joint ventures

We seek to work with companies that share our commitment to ethical, safe and sustainable working practices. However, we do not control how our co-venturers and their employees approach these issues.

Typically, our level of influence or control over a joint venture is linked to the size of our financial stake compared with other participants. In some joint ventures we act as the operator. Our OMS provides that where we are the operator, and where legal and contractual arrangements allow, OMS applies to the operations of that joint venture.

In other cases, one of our joint venture partners may be the designated operator, or the operator may be an incorporated joint venture company owned by BP and other companies. In those cases our OMS does not apply as the management system to be used by the operator, but is available to our businesses as a reference point for their engagement with operators and co-venturers. Where BP does not have overall control of a joint venture, we will do everything we reasonably can to make sure joint ventures follow similar principles.

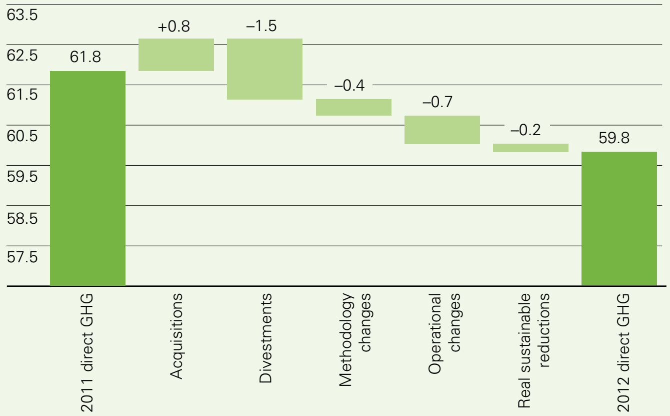
Environmental and social responsibility

We strive to minimize our impact on the environment and communities, to respect human rights and to conserve cultural heritage.

- Our operating management system (OMS) lays out the standards and processes required for environmentally and socially responsible operations.
- Our operations are expected to work to continually reduce their impacts and risks. All our major operating sites, with the exception of recently acquired operations, are required to be certified to the environmental management system standard ISO 14001.
- We seek to manage operational greenhouse gas (GHG) emissions through our OMS, which requires businesses to incorporate energy use considerations in their business plans and to assess, prioritize and implement technologies and systems to improve energy usage.

Greenhouse gas emissions

(Mte CO_2 equivalent)



Managing our environmental and social risks and impacts

At a group level, we review our management of material issues such as GHG emissions, water, sensitive and protected areas and human rights annually. We seek to identify emerging risks and assess methods to reduce them across the company.

Our OMS helps our operations around the world to assess and manage their environmental and social impacts. This includes conducting an annual OMS assessment to identify risks and impacts, and then putting in place action plans to manage them.

The principles and standards of OMS are supported by our environmental and social practices. These set out how our major projects identify and manage environmental and social impacts. They also apply to projects that involve new access, projects that could affect an international protected area and some BP acquisition negotiations.

In the early planning stages, these projects complete a screening process. Results are used to identify the most significant environmental and social impacts associated with the project, with a requirement to identify mitigation measures and implement these in project design, construction and operations. From April 2010 to the end of 2012, 88 projects had completed the screening process, and used outputs of the process to implement measures to reduce impact.

During screening, we identify any international protected areas that could be affected by the project, using the UNEP World Conservation Monitoring Centre's World Database on Protected Areas. Our international protected areas classification includes areas designated as protected by the International Union for the Conservation of Nature (categories I-IV), Ramsar and World Heritage sites, as well as areas proposed for international protected status.

Where screening indicates that a proposed BP project could affect an international protected area a high-level risk assessment is carried out, including identification of potential avoidance and mitigation measures. Our safety and operational risk function provides an independent review of the risk assessment, and before any physical activity begins, permission is sought from senior management. In 2012 no new projects sought permission for entry into an international protected area.

Our operations are expected to work to continually reduce their impacts and risks. All our major operating sites, with the exception of recently acquired operations, are required to be certified to the environmental management system standard ISO 14001, and publish an externally verified environmental statement. In 2012 our Gelsenkirchen refinery in Germany was not recertified due to conflicts in scheduling a verification audit. They completed a verification audit in late 2012 and were recertified in January 2013.

More information about our approach to environmental and social issues can be found in *BP Sustainability Review 2012* and at *bp.com/sustainability*.

Oil spill preparedness and response

We have used lessons from our Deepwater Horizon oil spill response to further enhance our internal approaches to preparedness and response planning. In July 2012 new group requirements for oil spill preparedness and response planning, and for crisis management were issued, with timeframes established for required conformance by the businesses. To facilitate understanding of these new requirements, workshops have been conducted with more than 600 staff from 45 countries, ranging from senior leaders to on-site oil spill response teams.

Understanding and mitigating the risks

Identifying and assessing the potential oil spill risks and potential impacts helps us to develop appropriate oil spill response and crisis management plans. These plans are backed up by the tools and people required to mount an effective response to an incident and mitigate potential impacts.

We further developed our oil spill modelling systems and capabilities in 2012. Improving existing modelling tools, conducting staff training in our regions and enhancing the environmental and socio-economic data required in the models have all helped to better define different oil spill scenarios and to plan for responding to them. Modelling for two deepwater drilling operations, Salamat and North Uist, indicated that international protected areas could potentially be affected from the worst case oil spill scenario. As a result, additional mitigations were put in place to try to reduce this risk.

Understanding the environmental and socio-economic sensitivities can help inform response planning. Across our operating regions, we are developing enhanced, high resolution sensitivity maps aided by the use of technologies such as remote sensing satellites. In 2012 we used high resolution satellite imagery to enhance sensitivity maps of coastlines in Brazil and Africa.

The use of oil spill dispersants as a response tool for major oil spills in the deep-sea environment continued to be a focus area in 2012. We continue to gain a greater understanding of dispersants and their use through scientific research programmes, conducted individually: for example, characterizing the 'oil-degrading bacterial communities' in our operating regions and collectively, through joint industry programmes such as IPIECA-OGP and the API.

Collaboration on lessons learned

We seek to work collaboratively with government regulators in planning for oil spill response, sharing lessons learned and our technical approaches, with the aim of improving any potential future response. In the past two years we conducted workshops on issues such as dispersant use and in-situ burn response to regulators in Australia, Brazil, China, Egypt, Indonesia, Norway and the UK.

We are advancing our capability to respond to potential incidents and are working with our industry to further enhance access to equipment and technologies around the world. BP's global deepwater well capping and tooling package is stored in Houston and can be deployed in a matter of days to anywhere in the world in the event of a deepwater well blowout.

The equipment is designed to operate in water depths of up to 10,000 feet. It includes a remotely operated vehicles intervention system, a subsea dispersant injection system and subsea debris removal equipment and a deepwater well cap.

See Safety on pages 46-50 for further information on BP's approach to oil spill prevention and for performance data on loss of primary containment.

Gulf of Mexico – our long-term commitments

See Gulf of Mexico oil spill on pages 59-62 for further information on BP's response to the incident and environmental and economic restoration efforts.

Climate change

Climate change represents a significant challenge for society and the energy industry, including BP. In response to the challenges and opportunities, BP is continuing to take a number of practical steps, including investing in lower-carbon energy products such as biofuels and wind, and ventures focused on sustainable energy solutions. We seek to manage our own GHG emissions through our OMS, by requiring our operations to incorporate energy use considerations in their business plans and to assess, prioritize and implement technologies and systems to improve energy usage.

As part of our OMS and project screening process, we consider and identify risks and potential impacts of a changing climate on our facilities and operations.

Greenhouse gas emissions

Our direct GHG emissions[a] were 59.8 million tonnes (Mte) in 2012, compared with 61.8Mte in 2011, a decrease of 2.0Mte versus 2011. The net effect of acquisitions and divestments is a decrease of 0.7Mte, primarily the result of the sale of upstream assets as part of our divestment programme. Operational changes led to a decrease of 0.7Mte, principally due to temporary reductions in activity at some of our upstream sites and one of our major US refineries and lower mileage by our shipping vessels. Improvements made by our businesses to calculate their emissions more accurately resulted in a net decrease of 0.4Mte. We achieved 0.2Mte of sustainable emissions reductions in 2012.

[a] We report GHG emissions 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.

Over the long term it is likely that the carbon intensity of our upstream operations will continue to trend upwards as we move further into technically challenging and potentially more energy-intensive areas. The carbon intensity will likely remain relatively flat or even decrease in certain refining operations because of improved energy efficiency even with the trend towards processing heavier crudes.

Greenhouse gas regulation

In the future, we expect that additional regulation of GHG emissions aimed at addressing climate change will have an increasing impact on our businesses, operating costs and strategic planning, but may also offer opportunities for the development of lower-carbon technologies and businesses.

To help address potential future regulation, we factor a carbon cost into our investment appraisals and engineering designs for new projects where appropriate. We do this in order to assess, and protect the value of, our new investments under future scenarios in which the cost of carbon emissions is higher than it is today. We require larger projects, and those for which emissions costs would be a material part of the project, to apply a standard carbon cost to the projected GHG emissions over the life of the project. The standard cost is based on our estimate of the carbon price that might realistically be expected in particular parts of the world. In industrialized countries, this standard cost assumption is currently $40 per tonne of CO_2 equivalent. We use this cost as a basis for assessing the economic value of the investment and as one consideration in optimizing the way the project is engineered with respect to emissions.

See Regulation of the group's business – Greenhouse gas regulation on pages 96-97.

Climate change adaptation

We are taking steps to prepare for the potential physical impacts of climate change on our existing and future operations. We are working closely with Imperial College in the UK to develop specialized climate models that help us better understand and predict possible impacts resulting from the changing climate.

Projects implementing our environmental and social practices are required to assess the potential impacts to the project from the changing climate and manage any identified significant potential impacts. Where climate change impacts are identified as a risk for a project, our engineers seek to address them in the project design like any other physical and ecological hazard. We periodically review and adjust existing design criteria and engineering technology practices. For example, a regional climate model was used in 2012 to inform decisions on the depth of cover required for river crossings for the South Caucasus Pipeline and to review any risks associated with landslides.

We regularly update and improve our climate impact modelling tools and make them available to both new projects and existing operations. An internal guide, available to both existing operations and projects, has been in place since 2010. It sets out guidance on how to assess potential risks and impacts from a changing climate to enable mitigation steps to be incorporated into project planning, design and operations.

Water

BP recognizes the importance of managing water effectively and efficiently in areas of water stress or scarcity, the need to minimize water quality impacts from our discharges, and the need to protect water resources at our operations.

We are continuing to pilot and develop standardized tools to more deeply understand the nature of the risks and opportunities associated with water management at a strategic and local level. This includes an assessment of water scarcity, the impact of changing effluent discharge standards, and the long-term social and environmental pressures on water resources within the local area. We also commissioned Harvard University in the US to conduct research in 2012 on the allocation and use of water in Jordan, the United Arab Emirates, Iraq and Oman. This will be followed through in 2013 and 2014 with more detailed research in three or four of these countries. This will equip BP with peer-reviewed science as a basis for planning water needs for oil and gas developments in the Middle East.

Unconventional gas and hydraulic fracturing

Natural gas resources, including unconventional gas, have an increasingly important role in meeting the world's growing energy needs. New technologies are making it possible to extract unconventional gas resources safely, responsibly and economically. BP has unconventional gas operations in the US, Algeria, Indonesia and Oman.

Hydraulic fracturing is the process of pumping water, mixed with a small proportion of sand and chemicals, underground at a high enough pressure to split and keep open the rock and release natural gas that would otherwise not be accessible. Some stakeholders have expressed concerns about the potential environmental and community impacts of this process.

BP recognizes these concerns and seeks to apply responsible well design, construction and operation to mitigate the risk that natural gas and hydraulic fracturing fluids enter underground aquifers, including drinking water sources. We are trialling a number of water-saving innovations to minimize the amount of fresh water used in our drilling and hydraulic fracturing operations.

Water and sand constitute on average 99.5% of the injection fluid. This is mixed with chemicals to create the fracturing fluid that is pumped underground at high pressure to fracture the rock with the sand propping the fractures open. The chemicals used in this process help to reduce friction and control bacterial growth in the well. Some of them are classified as hazardous materials, as are the constituents of many everyday products when in concentrated form. Each chemical used in the fracturing process is listed in the material safety data sheets at each site, which detail safe dosage limits. We submit data on chemicals used at our hydraulically fractured wells in the US at *fracfocus.org*.

At our operating sites, we aim to minimize air pollutant and GHG emissions by, for example, seeking to use natural gas or electricity instead of more carbon-intensive conventional fuel sources to power operations at sites where these energy sources are readily available and affordable. We introduced 'green completion' technology in our North American gas operations in 2001 to recover natural gas for sale and minimize the amount of natural gas either flared or vented from our wells.

To help manage potential impacts on the community, such as increased traffic, noise, dust and light, we seek to design and locate our equipment and manage our work patterns in ways that reduce impact to relevant communities. We also listen to suggestions or complaints from nearby local communities and try to address their concerns.

More information about our approach to unconventional gas and hydraulic fracturing may be found at *bp.com/unconventionalgas*.

Canada's oil sands

Canada's oil sands are believed to hold one of the world's largest supplies of oil, third in size to the resources in Saudi Arabia and Venezuela.

BP is involved in three oil sands properties, all of which are located in the province of Alberta. Development of the Sunrise project, our joint venture operated by Husky Energy, is under way, with production from Phase 1 expected to start in 2014. The other two proposed projects – Pike, which will be operated by Devon Energy, and Terre de Grace, which will be BP-operated – are still in the early stages of development.

Our decision to invest in Canadian oil sands projects takes into consideration GHG emissions, impacts on land, water use and local communities, and commercial viability. In the case of joint ventures in which we are not the operator, we monitor the progress of these projects and the mitigation of risk. In the Terre de Grace project where we are the operator, we are responsible for managing these potential impacts and the mitigation of risk.

More information on BP's investments in Canada's oil sands can be found at *bp.com/oilsands*.

Environmental expenditure

			$ million
	2012	2011	2010
Environmental expenditure relating to the Gulf of Mexico oil spill			
Spill response	**118**	671	13,628
Additions to environmental remediation provision	**801**	1,167	929
Other environmental expenditure			
Operating expenditure	**742**	704	716
Capital expenditure	**1,207**	819	911
Clean-ups	**46**	53	55
Additions to environmental remediation provision	**549**	510	361
Additions to decommissioning provision	**3,756**	4,596	1,800

Environmental expenditure relating to the Gulf of Mexico oil spill

BP continues to incur significant costs related to the 2010 Gulf of Mexico oil spill. The spill response cost incurred during 2012 is $118 million (2011 $671 million), and $345 million (2011 $336 million) remains as a provision at 31 December 2012.

The environmental remediation provision includes amounts for BP's commitment to fund the Gulf of Mexico Research Initiative, estimated natural resource damage (NRD) assessment costs and early NRD restoration projects under the $1-billion framework agreement. The provision for NRD assessment costs was increased during the year. Further amounts for spill response costs were provided during the year, primarily to reflect increased costs for patrolling and maintenance and shoreline treatment projects. The majority of the active clean-up of the shorelines was completed in 2011.

See Financial statements – Note 2 on page 194, Note 36 on page 235 and Note 43 on page 253 for further information relating to the Gulf of Mexico oil spill.

Other environmental expenditure

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 forms 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 $742 million in 2012 was at a similar level to 2010 and 2011.

Capital expenditure in 2012 was higher than in 2011 principally due to the high level of construction activity at our Whiting refinery in relation to new units as part of the Whiting refinery modernization project which is due to be completed in the second half of 2013. Similar levels of operating and capital expenditures are expected in the foreseeable future.

In addition to operating and capital expenditures, we also establish 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.

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 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.

Additions to our environmental remediation provision increased in 2012 largely due to scope reassessments of the remediation plans of a number of our sites in the US and Canada. The charge for environmental remediation provisions in 2012 included $19 million in respect of provisions for new sites (2011 $12 million and 2010 $54 million).

In addition, we make 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.

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. The significant increases in 2010 and 2011 were driven by changes in estimation and detailed reviews of expected future costs. The majority of these increases related to our sites in Trinidad, the Gulf of Mexico and the North Sea.

The Gulf of Mexico was impacted by the Bureau of Ocean Energy Management, Regulation and Enforcement's (BOEMRE) Notice to Lessees (NTL) 2010-G05, issued in October 2010, which requires that idle infrastructure on active leases is decommissioned earlier than previously was required and establishes guidelines to determine the future utility of idle infrastructure on active leases.

In 2012 additions to the decommissioning provision were less than in 2011, although still significant, and were again driven by detailed reviews of expected future costs. The majority of the additions related to our sites in the North Sea, Alaska, the Gulf of Mexico and Angola.

We undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments.

Provisions for environmental remediation and decommissioning are usually established 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 36 on page 235.

Respecting human rights

In 2012 we developed a human rights policy in consultation with businesses and functions, and we expect to launch it in 2013. The policy builds on commitments in our code of conduct regarding communities, workforces and the supply chain and we expect to report annually on its implementation. See page 56 for further information about our code of conduct.

We understand our responsibility to respect the human rights of the communities and workforces with whom we interact. BP supports the Universal Declaration of Human Rights, which lays out the rights to which all human beings are entitled. Our policy sets out our commitment to respect all internationally recognized human rights, including those set out in the International Bill of Human Rights and the International Labour Organization's Declaration on Fundamental Principles and Rights at Work.

We are a signatory to two voluntary agreements with implications for specific aspects of human rights: the UN Global Compact, which includes principles on protecting internationally proclaimed human rights, and the Voluntary Principles on Security and Human Rights, which define good practice for security operations in the extractive industry.

In 2011 we used external consultants to carry out a comparison between our current policies and practices and the expectations in the Guiding Principles. In 2012 we used the findings to create an action plan designed to achieve closer alignment with the Guiding Principles over a number of years. Planned actions include:

- Developing and implementing human rights training prioritizing specific businesses and functions.
- Developing guidance on integrating human rights into impact assessments and community grievance processes.
- Embedding human rights requirements into our procurement and supply chain management processes.

A steering committee has provided oversight for the development of the planned actions.

We are participating in the work of oil and gas industry organization IPIECA's human rights taskforce, and are contributing our experience to develop practical guidance for the industry on integrating human rights into impact assessments and community grievance processes.

More information about our approach to human rights may be found at *bp.com/humanrights*.

Revenue transparency and business ethics

As a member of the Extractive Industries Transparency Initiative (EITI), we work with governments, non-governmental organizations and international agencies to improve transparency on revenue disclosures. In several countries that are in the process of becoming EITI compliant, BP is supporting the process. For example, BP is an active member of the Trinidad & Tobago EITI steering committee. In countries that have achieved EITI compliance, including Azerbaijan and Norway, BP submits an annual report on payments to their governments.

We have taken part in consultations in relation to new or proposed revenue transparency reporting requirements in the US and Europe for companies in the extractive industries. BP will comply with the relevant laws and regulations in force.

We are working to respond effectively to the standards arising from the UK Bribery Act as well as other anti-corruption legislation such as the Foreign Corrupt Practices Act and certain regulations promulgated under the Dodd-Frank Wall Street Reform and Consumer Protection Act in the US.

Bribery and corruption are serious risks in the oil and gas industry. Our code of conduct requires that our employees or others working on behalf of BP do not engage in bribery or corruption in any form in both the public and private sectors. We operate a group-wide anti-bribery and corruption standard, which applies to all BP employees and contractors. The standard requires annual bribery and corruption risk assessments; due diligence on all parties with whom BP does business; appropriate anti-bribery and corruption clauses in contracts; and the training of personnel in anti-bribery and corruption measures.

Enterprise and community development

We run a range of programmes to build the skills of businesses in places where we work and to develop the local supply chain. The programmes can benefit local companies by empowering them to reach the standards needed to supply BP and other organizations. For example, we provide training and share standards in areas such as health and safety. At the same time BP benefits from the local sourcing of goods and services.

BP's social investments, the contributions we make to social and community programmes in locations where we operate, support development activities that aim for a meaningful and sustainable impact. We look for social investment opportunities that are relevant to local needs, aligned with BP's business, and offer partnerships with local organizations. The programmes we support include building business skills and developing enterprise, supporting education and other community needs and sharing technical expertise with local and national host governments. In a few locations we also support small community infrastructure programmes that help people improve their access to basic resources such as drinking water and public health services. We work with local authorities, community groups and specialists to deliver these community programmes.

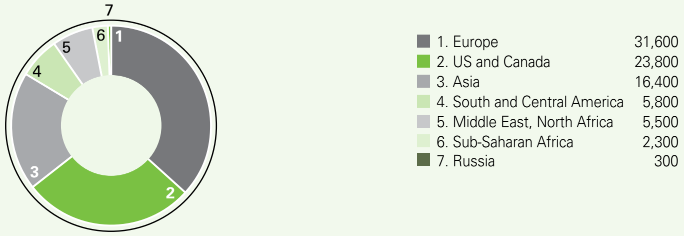
Our direct spending on community programmes in 2012 was $90.6 million, which included contributions of $31.7 million in the US, $16.3 million in the UK (including $6.9 million to UK charities, of which $4.8 million for arts and culture, and $2.1 million for education), $2.3 million in other European countries and $40.3 million in the rest of the world, including disaster relief. These reported amounts exclude social bonuses paid by BP to governments as part of licence acquisition costs and that have been capitalized as intangible assets on the group balance sheet. In such cases the group has no direct oversight of the expenditure. Contributions relating to economic recovery following the Deepwater Horizon oil spill are also excluded, see page 60 for details of these contributions.

Employees

To be sustainable as a business, BP needs employees who have the right skills for their roles and who understand the values and expected behaviour that guide everything we do as a group.

- Our values and code of conduct define the expected qualities and actions of all our people.
- Succession planning is a board-level priority, and we hire and retain the best people and systematically manage and develop their potential.
- We aim for a workforce that is engaged and that is representative of the societies where we operate.

BP group headcount by region[a] (including service station staff)



Number of employees at 31 December[a]	US	Non-US	Total
2012			
Upstream	**9,500**	**14,500**	**24,000**
Downstream[b]	**11,900**	**39,400**	**51,300**
Other businesses and corporate	**1,900**	**8,400**	**10,300**
Gulf Coast Restoration Organization	**100**	**–**	**100**
	23,400	**62,300**	**85,700**
2011			
Upstream	8,900	13,300	22,200
Downstream[b]	12,000	39,000	51,000
Other businesses and corporate	1,900	8,200	10,100
Gulf Coast Restoration Organization	100	–	100
	22,900	60,500	83,400
2010			
Upstream	7,900	13,200	21,100
Downstream[b]	12,400	39,900	52,300
Other businesses and corporate	1,700	4,500	6,200
Gulf Coast Restoration Organization	100	–	100
	22,100	57,600	79,700

[a] Reported to the nearest 100.

[b] Includes 14,700 (2011 14,600 and 2010 15,200) service station staff, all of whom are non-US.

We had approximately 85,700 employees at 31 December 2012, compared with approximately 83,400 at the same time in 2011. During 2012 our headcount has increased by about 3%. This is a result of a focused effort to re-shape the business and strengthen capability.

Our values

Our values of safety, respect, excellence, courage and one team align explicitly with BP's code of conduct and translate into the responsible actions necessary for the work we do every day. Our values represent the qualities and actions we wish to see in BP, they guide the way we do business and the decisions we make.

We work with our employees to raise their awareness of our values and to help them embed the values in all activities. In 2012 we worked on embedding BP's values into many of our group-wide systems and processes, including our recruitment, promotion and development assessments. See *bp.com/values* for more information.

People policies

The group people committee, chaired by the group chief executive, has overall responsibility for key policy decisions relating to employees. In 2012 subjects discussed included longer-term people priorities; quarterly reviews of progress in our diversity and inclusion programme; the rolling out and embedding of our revised performance review procedures; and the continuing development of our learning programmes.

We have a good understanding of our future demand for people and where they will come from. Building our employees' capability is a priority, as is rewarding them in a way that aligns with our goals. We focus on ensuring the safety of our employees, engaging with them, and increasing the diversity of our workforce so that it reflects the societies in which we operate.

Attracting and retaining our people

The increasing demand for energy products and the complexity of our projects means that attracting and retaining skilled and talented people is vital to the delivery of our strategy and plans.

In support of this, the group chief executive and each member of the executive team hold regular review meetings to ensure that appropriate plans to build capability are in place and that a rigorous and consistent succession process is followed for all group leadership roles.

To supplement our existing internal capability, we also target experienced and skilled professionals in the external market and are continuing to increase our intake of graduates to create a strong internal talent pipeline for the future. We have tailored training programmes for graduates and post-graduates to develop BP's future leaders.

Our graduate development programme currently has around 1,600 participants. To address increasing demands for skilled people outside the US and UK, more than 40% of 2013's graduate recruitment is targeted at universities in growing markets. We invest in universities worldwide to further develop the quality of our potential recruits.

We conduct external assessments for all new hires into BP at senior levels and for internal promotions to senior level and group leader level roles. These assessments help ensure rigour and objectivity in our hiring and talent processes. They give an in-depth analysis of leadership behaviour, intellectual capacity and the required experience and skills for the role in question.

Building enduring capability

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 at least five training days a year.

We continue to work to embed appropriate leadership behaviours throughout our organization. By 2012 our group-wide suite of management development programmes, managing essentials, had been attended by employees from 74 countries, in four regions and in 10 different languages.

We provide world-class education opportunities for our people, partnering with 19 academies and institutes that deliver technical learning and development.

Meeting the expectations of our people

We have reviewed our reward strategy, including how the group incentivizes business performance, with the aim of encouraging excellence in safety, compliance and operational risk management. In annual performance reviews all staff are required to set priorities for themselves in these three areas.

We encourage employee share ownership. For example, through our ShareMatch plan run in around 50 countries, we match BP shares purchased by our employees. We have also consolidated our equity plans into one single company-wide plan, and extended this to more junior members of staff. The plan is linked to the company's performance, with the same measure for everyone.

We aim to treat employees affected by divestments, mergers, acquisitions and joint ventures fairly and with respect, through open and regular communication. When divestments do occur, BP seeks the same or comparable pay and benefits for employees transferring to other companies.

Diversity and inclusion

We are a global company and aim for a workforce that is representative of the societies in which we operate. For our employees to be properly motivated and to perform to their full potential, and for the business to thrive, our people need to be treated with respect and dignity, and without discrimination.

Through living our values we create an inclusive working environment where everyone can make a difference and give their best. Our work on diversity and inclusion is overseen by the group people committee who reviews performance on a quarterly basis. The committee agrees strategic direction and group standards which are then implemented through business-specific diversity and inclusion plans. In 2012 we launched a framework to set out our ambition and drive further progress across the group. It includes statements of wide-ranging improvements we hope to achieve by 2016.

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 2012, 17% of our group leaders were female and 22% 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 supported the UK government-commissioned Lord Davies review in 2011, which made recommendations on increasing gender diversity on the boards of listed companies. See page 113 – governance report.

We are also incorporating detailed diversity and inclusion analysis into talent reviews, with processes to identify actions where any issues are found. We continue to increase the number of local leaders and employees in our operations so that they reflect the communities in which we operate and this is monitored at a local, business or national level.

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.

Employee engagement

Executive team members hold regular town-hall style meetings and webcasts to communicate with our employees around the world.

Team meetings and one-to-one meetings are 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, ethical, social and environmental factors affecting our performance. The group seeks to maintain constructive relationships with labour unions.

We conduct an annual survey of our employees – with more than 55,000 employees in around 70 countries for 2012 – to monitor employee engagement and identify areas where we can improve this. The 2012 results show levels of engagement are up across all levels and business areas.

Business leadership teams review the results of the survey and agree actions to address the identified issues. Safety scores remain strong although there is more work for us to do in continuing to embed our OMS as the way BP operates so people fully understand what it means for them.

We also measure how engaged our employees are with our strategic priorities of safety, trust and value. The group priorities engagement measure is derived from 12 questions about employee perceptions of BP as a company and how it is managed in terms of leadership and standards. Aggregate results for these questions showed a 4% improvement on 2011 to 71%.

Alongside engagement, a new indicator of employee and workplace satisfaction was introduced in 2012, replacing the previous employee satisfaction index (ESI). This new measure is more comprehensive than the previous index and looks at management behaviour, job satisfaction, development and reward. The aggregate score for employee and workplace satisfaction in 2012 was 71%. For comparison, the ESI, based on a narrower set of measures, rose by 4% to 66%.

The BP code of conduct

The BP code of conduct sets the standard that all BP employees are required to work to. It is based on our values and it clarifies the ethics and compliance expectations for everyone who works at BP.

The code defines what BP expects of its people in key areas such as safety, workplace behaviour, bribery and corruption and financial integrity. The code is based on four foundations: what we do, what we stand for, what we value and speaking up.

Employees, contractors or other third parties who have questions or concerns that laws, regulations or the code of conduct may be breached, can get help through OpenTalk, a helpline that is operated by an independent company. The number of cases raised through OpenTalk in 2012 was 1,295, compared with 796 in 2011. In the US, former 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 2012, 424 dismissals were reported by BP's businesses for non-adherence to the code of conduct or unethical behaviour compared with 529 in 2011. This excludes dismissals of staff employed at our retail service station sites, for incidents such as thefts of small amounts of money. A new reporting process to capture information on dismissals is presently being put in place for 2013.

Following the settlement with the US government of all federal criminal claims related to the Gulf of Mexico, BP has agreed to appoint an ethics monitor in the US for a term of four years to review and provide recommendations for the improvement of BP's code of conduct and its implementation and enforcement.

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. We review employees' rights to political activity in each country where we operate. For example, in the US, BP facilitates staff participation in the political process by providing staff support to ensure BP employee political action committee contributions are publicly disclosed and comply with the law.

Technology

BP develops and deploys technology to find and produce more hydrocarbons, improve conversion efficiency and build new lower-carbon businesses.

Technology investment

Activity	Point of competition	Technology focus
Resource extraction	Access	• Subsurface understanding • Standardized engineering solutions • Unconventional hydrocarbons
Conversion	Efficiency	• Chemical process technology • Upgrading refineries
Consumption	Formulation	• Lubricants • Advanced fuels
Lower carbon	Feedstocks and conversion technologies	• Biofuels

2012 highlights:

- We spent $674 million on research and development (R&D) in 2012, supporting business priorities across our portfolio.
- We successfully progressed a suite of technologies aimed at improving safety and operational risk management. Highlights include: demonstration of our real-time blowout preventer (BOP) monitoring tool offshore Brazil; digital radiography to assess the integrity of subsea systems in the North Sea; and deployment of Permasense® corrosion probes to monitor the wall thickness of equipment in refineries in real time.
- We announced plans to deploy *LoSal* enhanced oil recovery technology at our Clair Ridge development in the UK North Sea, which we believe will lead to significantly increased amounts of recoverable oil (see Salt reduction promises healthy returns on page 17).
- We awarded first contracts for Project *20K*, a multi-year initiative to develop next-generation systems and tools to unlock high pressure oil and gas resources in deep water.
- We began construction of a new High-Performance Computing (HPC) centre in Houston, designed to ensure BP remains at the forefront of subsurface imaging technology.
- We licensed our latest-generation purified terephthalic acid (PTA) and paraxylene (PX) technologies to non-affiliated third-parties for the first time, and sold our third licence for *Veba combi-cracking (VCC)* technology.
- In lubricants, we launched new *Castrol* products: *EDGE with Titanium* to deliver enhanced protection under extreme conditions; and *Magnatec Hybrid* to tackle the challenges of engines working with hybrid and stop/start powertrains.
- We are investing $100 million over 10 years to set up the International Centre for Advanced Materials (ICAM) to fund research into fundamental understanding and use of advanced materials, from self-healing coatings to membranes, across the energy industry.

How we manage technology

We define technology in BP as the practical application of science to manage risks, capture business value and inform strategy development. This includes the research, development, demonstration and acquisition of new technical capabilities and support for the deployment of BP's know-how.

Our investments are focused on safe operations and areas of competitive advantage: access to resources, process efficiency, product formulation and lower-carbon opportunities.

In 2012 we invested $674 million in R&D (2011 $636 million). (See Financial statements – Note 13 on page 210.)

The group technology function provides input to BP's strategy, oversees our major technology programmes, supports technology development and deployment across the company, builds science capability and conducts long-term research.

The technology advisory council, comprised of eminent business and academic technology leaders, provides the board and executive management with an independent view of BP's capabilities judged against the highest industrial and scientific standards.

BP has more than 2,000 scientists and technologists across the group, with seven major technology centres in the US, the UK and Germany.

We also access external expertise through various forms of partnership and collaboration, from joint research agreements to venturing. We have a strategic approach to university relationships across our portfolio for the purposes of research, recruitment, policy insights and education.

Long-term research programmes

International Centre for Advanced Materials (ICAM)

In 2012 BP announced the establishment of ICAM, a $100-million 10-year research partnership to fund research aimed at advancing the fundamental understanding and use of advanced materials from self-healing coatings to membranes, across a variety of energy and industrial applications. The University of Manchester will be the 'hub' for a network of world-class academic institutions, with the University of Cambridge, Imperial College London and the University of Illinois at Urbana-Champaign already participating.

Energy Sustainability Challenge (ESC)

BP is partnering with leading research universities to establish trusted peer-reviewed data on the relationships between natural resource usage and energy. The ESC is a multi-disciplinary research programme, aimed at building a better understanding of natural resource constraints on energy production and consumption – including land, water and mineral resources.

Initial findings of the ESC suggest that energy-related natural resource constraints can be managed, but doing so will not be easy, and will require wise policy decisions and technology choices. The next phase of the research will focus on a number of specific natural resource challenges for our businesses and operations across the world.

More information on the ESC can be found at *bp.com/energysustainabilitychallenge*.

The Energy Biosciences Institute (EBI)

The EBI is BP's largest external R&D collaboration, with up to $500-million funding over 10 years for a multi-disciplinary research effort with the University of California Berkeley, the Lawrence Berkeley National Laboratory, and the University of Illinois at Urbana-Champaign. Its goal is to perform groundbreaking research aimed at the development of next-generation biofuels, as well as other bioscience applications to the energy sector. Now in its fifth year, the EBI is generating multiple innovations, particularly in the field of cellulosic conversion.

Massachusetts Institute of Technology Energy Initiative (MITEI)

In 2012 BP renewed its commitment to the MITEI through an agreement to provide another $25 million for continued energy research over the next five years, bringing the company's total programme funding to $50 million. The MITEI conducts multi-disciplinary research aimed at tackling complex energy challenges such as increasing energy supply, improving efficiency, and addressing environmental impacts of energy consumption. To date, the initiative has sponsored hundreds of energy projects ranging from unconventional sources of hydrocarbons to renewables and nuclear fusion.

Energy Technologies Institute (ETI)

BP is a founding member of the UK's Energy Technologies Institute – a public/private partnership established in 2008 to accelerate lower-carbon technology development. By the end of 2012 the ETI had commissioned more than $281 million of work covering 41 projects across a wide range of technologies.

Upstream

Our upstream technologies support BP's business strategy by:

- Focusing on safety and operational risks.
- Helping to obtain new access.
- Increasing recovery and reserves.
- Improving production efficiency.

Our strengths in exploration, deep water, giant fields and gas are underpinned by dedicated flagship technology programmes. These undertake proprietary scientific research to develop industry-leading technologies such as imaging, enhanced recovery and real-time data capabilities. (See Upstream technology flagships on page 18.)

In 2012:

- We began construction of a new HPC centre in Houston, our laboratory for processing and analysing seismic images. BP's investment in the new 110,000 square foot (10,209 square metres) facility will help drive seismic imaging beyond the methods we know today, extending BP's scientific and technical capability. The facility is due for completion in mid-2013.
- The BP Well Advisor suite of technologies aims to bring wells online more efficiently and enhance safety through providing real-time information for decision making. A major programme is under way to develop and deploy BP Well Advisor tools, from casing running, already installed in Azerbaijan, to BOP monitoring in Brazil, cementing in the North Sea and pressure testing in the Gulf of Mexico. These integrated systems provide consoles for the rig crew and onshore engineers to monitor operations in real-time, during well construction and over the life of the well. BP has selected Kongsberg as vendor for the consoles, which will provide a standard interface for drilling teams across the world. In 2012 we continued industry-first field trials of our BOP diagnostic tool on the Ensco DS4 rig offshore Brazil. This technology has been shared with the industry and with the US Bureau of Safety and Environmental Enforcement.
- In February 2012 we announced the launch of Project *20K*, a multi-year initiative to develop next-generation systems and tools to help recover high-pressure, high-temperature deepwater oil and gas resources. We intend to develop technologies over the next decade in four key areas: well intervention and containment; well design and completions; drilling rigs, riser and BOP equipment; and subsea production systems. In November 2012 we awarded the first contracts for Project *20K* to KBR and FMC Technologies. KBR will develop programme execution and management plans, including capital cost and schedule estimates, risk assessments and technical designs. FMC Technologies will participate in a technology development agreement in which it will work jointly with BP to design and develop 20,000 pounds per square inch rated subsea production equipment, including a subsea production tree and a subsea high integrity pressure protection system.
- BP announced a plan to deploy its *LoSal* enhanced oil recovery (EOR) technology at the Clair Ridge development in the UK North Sea. This will be the first large-scale offshore deployment of this BP enhanced oil recovery application. The $7.6-billion development at Clair Ridge includes around $120 million for the desalination facilities to create low salinity water. BP estimates that this breakthrough technology (part of BP's suite of *Designer Water* EOR technologies) will increase production by around 42 million barrels of additional oil, compared with conventional waterflooding methods. BP has also confirmed that Mad Dog phase 2 project in the Gulf of Mexico will be the next offshore deployment of *LoSal*.
- In collaboration with GE and Oceaneering, we completed BP's first full-field trial of shallow water subsea digital radiography technology (DRT) in the Madoes field in the UK North Sea. This technology employs imaging technology similar to that used in the medical field, adapted for use in marine environments for improved inspection of subsea flow lines up to 2,000 feet below the surface. BP also collaborated with JME, Oceaneering and GE in developing an alternative technology for use in the inspection of subsea flow lines located in deep water.

Downstream

Our Downstream technology focus is both operational and customer facing:

- Developing and applying technology to monitor operational integrity.
- Improving process efficiency in our refineries and petrochemicals plants.
- Optimizing conversion of unconventional feedstocks, including renewables, to liquid transport fuels and chemicals.
- Creating high-performance, energy-efficient, cleaner fuels and lubricants for customers.

Petrochemicals

- Our proprietary processing technologies and operational experience continue to reduce the manufacturing costs and environmental impact of our plants, helping to maintain competitive advantage in PTA, PX and acetic acid. For the first time, we have licensed our latest generation aromatics technology to non-affiliated third parties; firstly PTA technology to JBF Petrochemicals, and secondly PX technology to Reliance through our exclusive licensor, CB&I Lummus, both in India.

Lubricants

- We completed a number of product developments and launches. *Castrol EDGE with Titanium* is proven to reduce metal to metal contact and delivering enhanced protection under extreme conditions and *Castrol Magnatec Hybrid* tackles the challenges of engines working with hybrid and stop/start powertrains. We also launched an oil co-engineered with Ford during the development of its newly-released EcoBoost™ engine. This oil delivers a benefit of around 1% to fuel economy. In the commercial transport sector, we launched an updated *Castrol CRB* product, which offers enhanced protection and durability for truck engines. The launch of our new Performance Biolubes product range added bio-based lubricants for use in metalworking operations, improving productivity, safety and environmental impact.

Fuels

- We demonstrated our biofuels proprietary technology and collaboration by providing three specially formulated advanced biofuels (containing bio-derived components including cellulosic ethanol, diesel from sugar and biobutanol). These, blended with *BP Ultimate*, fuelled some of the vehicles in the official London 2012 Olympic and Paralympic Games fleet. We also continue to work proactively with governments and regulatory bodies in all countries where we operate to develop practical and effective solutions to meet local and regional biofuel mandates.

Conversion technologies

- *Veba Combi Cracking (VCC)* upgrades heavy oil or coal into high-value transport fuel by adding hydrogen and a proprietary ingredient that prevents unwanted carbon deposits fouling equipment, making the process more reliable. BP has a collaboration agreement on VCC with KBR, who are promoting, marketing and licensing the technology to third parties. In 2012, the third VCC licence with the largest capacity was secured to implement the technology at the Nizhnekamsk refinery in Russia.
- BP has developed a proprietary Fischer-Tropsch (FT) technology and a route to upgrade products from the FT process to transport fuel and chemical feedstocks such as diesel, kerosene and naphtha. Having proved this technology under commercial conditions, we and our collaborator Davy Process Technology are actively pursuing commercialization including licensing the technology to third parties. Technology licensing combined with recent successful demonstrations of improvements to both process and catalyst are underpinning the longer-term competitiveness of our technology.

Refining technologies

- We have made improvements in integrity management by deploying Permasense® wireless corrosion sensors in selected areas of all BP-operated refineries worldwide to monitor and enable better decisions about corrosion management. We developed this technology in collaboration with Imperial College, London.

Biofuels

- In addition to our biofuel production business in Brazil, we continue to invest in and operate a world-class biofuels research facility in San Diego, California, and a demonstration plant in Jennings, Louisiana, to further develop our next-generation cellulosic biofuel technology and license it for commercial use.
- BP's joint venture with DuPont, Butamax Advanced Biofuels LLC, is working to develop and market the advanced biofuel, biobutanol. A technology demonstration plant has been constructed in Hull, UK to accelerate the commercialization of biobutanol technology.
- BP is also working in partnership with DSM to advance the development of a step-change technology for conversion of sugars into renewable diesel.

Technology venturing

Our portfolio of technology venturing investments aims to put us at the forefront of innovation. Our emerging business and ventures unit brings together BP's venturing and carbon markets expertise with carbon capture and storage capability. Through this unit, we have invested about $175 million in 33 investments, spanning the following areas:

- Bioenergy.
- Energy efficiency and storage.
- Carbon management.
- Renewable power.
- Emerging oil and gas technologies.

Our recent investments include:

- Oxane Materials, a company that is commercializing advanced materials, such as ceramic proppants to improve production and reduce the environmental impact of hydraulic fracturing.
- Skyonic, whose SkyMine® technology is a novel application of carbon capture principles that can be retrofitted onto power plants and other industrial sites that emit high volumes of CO_2.
- Heliex Power, whose rotary screw expander technology can recover waste heat from a variety of sources commonly found in industry and use it to generate electricity.
- Liquid Light, a company developing new ways of converting CO_2 into high-performance chemicals and fuels.

More information on BP and technology can be found at *bp.com/technology*.

Gulf of Mexico oil spill

We remain committed to meeting our responsibilities to the US federal, state and local governments and communities of the Gulf Coast following the Deepwater Horizon accident.

Key events included:

- Continuing the clean-up of the Gulf shoreline under the direction of the Federal On-Scene Coordinator and working to progress the clean-up of shorelines to the point where removal actions are deemed complete.
- Supporting economic recovery by resolving legitimate claims and providing support to two of the region's most important industries – tourism and seafood.
- Reaching settlement agreements to resolve the substantial majority of legitimate private economic loss and medical claims – final approval was granted by the court on 21 December 2012 for the economic loss settlement agreement and on 11 January 2013 for the medical settlement agreement.
- Completing the funding of the $20-billion Deepwater Horizon Oil Spill Trust, which was established to pay individual and business claims, final judgments in litigation and litigation settlements, state and local response costs and claims, and natural resource damages and related costs.
- Working in co-operation with state and federal trustees to collect data needed to assess potential injuries to natural resources resulting from the accident and to progress early restoration activities.
- Supporting independent research through the Gulf of Mexico Research Initiative to better understand and mitigate the potential impacts of future oil spills.
- Reaching an agreement with the US government in November 2012 (which was subsequently approved by the court in January 2013) to pay $4 billion to resolve all federal criminal claims arising out of the Gulf of Mexico incident. BP also reached a settlement with the SEC to resolve the SEC's Deepwater Horizon-related civil claims against BP. Following these agreements, BP Exploration & Production Inc. (BPXP) received notice from the US Environmental Protection Agency (EPA) of a mandatory debarment from contracting with the US federal government, as well as notice of a temporary suspension, in respect of certain BP group companies. See Agreement with the US government on page 61 for further information.
- On 25 February 2013, the first phase of a Trial of Liability, Limitation, Exoneration and Fault Allocation commenced in the federal multi-district litigation proceeding in New Orleans (MDL 2179). This phase will address issues arising out of the conduct of various parties allegedly relevant to the loss of well control at the Macondo well, the ensuing fire and explosion on the Deepwater Horizon on 20 April 2010, the sinking of the vessel on 22 April 2010 and the initiation of the release of oil from the Deepwater Horizon or the Macondo well during those time periods, including whether BP or any other party was grossly negligent. See page 164 for further information.

We have made significant progress in completing the response to the accident and supporting economic and environmental recovery efforts in affected areas.

Completing the response

BP, working under the direction of the US Coast Guard's Federal On-Scene Coordinator (FOSC), continued to complete the Deepwater Horizon operational response activities in 2012.

Residual clean-up of the Gulf of Mexico shoreline

Throughout the year, BP continued to work to progress the clean-up of shorelines to the point where removal actions are deemed complete as established by the Shoreline Clean-up Completion Plan, which was approved by the FOSC in November 2011. The plan established the clean-up requirements for the range of shoreline types in the area of response and describes the rigorous process for determining that operational removal activity is complete.

By the end of 2012, the FOSC had deemed removal actions complete on 4,029 miles (6,484kms) of shoreline out of the 4,376 miles (7,043kms) that were in the area of response. Approximately 108 miles were pending final monitoring or inspection and a determination that removal actions are complete. The remaining 239 miles are in the monitoring and maintenance phase, which will continue until the FOSC determines that operational removal activity is complete.

According to a study by the Operational Science Advisory Team (OSAT), composed of scientists representing federal agencies and BP, the residual oil that remains is heavily weathered, contains only a small fraction of the compounds of concern and is below the EPA's benchmarks for the protection of human health.

The US Coast Guard has indicated that if oil is later discovered in a shoreline segment where removal actions have been deemed complete, they will follow long-standing response protocols established under the law and contact whoever it believes is the responsible party or parties.

Hurricane Isaac

In late August 2012, Hurricane Isaac made landfall on the Gulf Coast, uncovering residual oil in some areas in Louisiana. The remaining residual oil had been buried when tropical storms in 2010 and 2011 deposited several feet of sand along some of the Gulf Coast shoreline. After the material was buried, in many instances, net environmental benefit analysis had indicated that deep cleaning at these sites could do more harm than good. But once Isaac removed this sand overburden in some places, clean-up crews have been able to clean the residual material without the same degree of potential environmental impact.

Other shorelines in the area of response were less affected by Hurricane Isaac. A few areas saw a short-term increase in the number of tar balls in the initial aftermath, but conditions returned to pre-Isaac levels after a few days once clean-up operations were resumed in these locations.

Response efforts guided by science

Scientific studies conducted at the direction of the FOSC continued to guide response actions and help define what is known scientifically about the fate of the oil and the potential impacts to human health, aquatic life, wildlife and the environment. This included OSAT studies and net environmental benefit analyses conducted in 2010 and 2011.

At the request of BP, the FOSC formed another OSAT in 2012 to investigate discrete areas of buried oil accumulations (tar mats) near the shoreline. The team was directed to integrate a number of data sets to evaluate the potential for buried oil in discrete locations across the area of response and determine if additional mitigating actions may be taken to excavate the residual material with minimal environmental impact.

Economic recovery

BP continued to support economic recovery efforts in local communities through a variety of actions and programmes in 2012. By 31 December 2012, BP had spent nearly $10 billion on economic recovery, including claims, advances, settlements and other payments, such as state tourism grants and funding for state-led seafood testing and marketing. In addition, $1.8 billion has been paid to the seafood compensation fund, which has not yet been paid to final claimants.

Plaintiffs' Steering Committee settlements

In April 2012, BP reached settlements with the Plaintiffs' Steering Committee (PSC) to resolve the substantial majority of legitimate economic loss and medical claims stemming from the accident. In May 2012, the court preliminarily approved the settlements. The PSC acts on behalf of individual and business plaintiffs in the multi-district litigation proceedings pending in New Orleans.

Typically in class action settlements, claims are not paid until after the court has granted final approval to the settlement and all appeals have been exhausted. Here, BP took the unusual step of agreeing to process and pay claims under the economic and property damages agreement prior to any such court approval. Accordingly, a court-supervised transitional claims programme took over the processing and payment of economic loss claims from the Gulf Coast Claims Facility on 8 March 2012.

On 4 June 2012, the transitional process was closed, and the Deepwater Horizon Court Supervised Settlement Program (DHCSSP) began processing and paying claims from settlement class members under the economic and property damages agreement.

In November 2012, the court held a fairness hearing with respect to the settlements and subsequently granted final approval of the economic and property damages agreement on 21 December 2012 and of the medical benefits class action settlement agreement on 11 January 2013.

Under the economic and property damages agreement, there are agreed compensation protocols for the payment of class members' economic and property damages. In addition, many economic and property damages settlement class members will also receive payments based on negotiated risk transfer premiums, which are multipliers designed to compensate claimants for potential future losses relating to the accident, along with other potential damages.

Under the medical benefits class action settlement agreement, payments will be made based on a matrix for certain specified physical conditions. The agreement also provides for a 21-year Periodic Medical Consultation Program for qualifying class members. Class members claiming later-manifested physical conditions may pursue their claims in the future through a mediation or litigation process, but waive the right to seek punitive damages.

In addition, under the medical benefits class action settlement agreement, BP has agreed to provide $105 million to the Gulf Region Health Outreach Program to improve the availability, scope and quality of healthcare in Gulf communities. The focus will be on strengthening local capacity to deliver primary care, behavioural and mental health services, and environmental medicine. This healthcare outreach programme is intended to benefit both class members and others in those communities. BP provided approximately $20 million in 2012 to launch the assessment and evaluation phase of the health outreach programme across the four Gulf States.

Business economic loss claims received by the DHCSSP to date are being paid at a higher average amount than previously assumed by BP in formulating the original estimate of the cost of the PSC settlement, resulting from an interpretation of the settlement agreement by the claims administrator that BP believes was incorrect. As more fully described in Legal proceedings on pages 162-169, this matter has been considered by the court and on 5 March 2013, the court affirmed the claims administrator's interpretation of the settlement agreement and rejected BP's position as it relates to business economic loss claims. BP strongly disagrees with the ruling of 5 March 2013 and the current implementation of the agreement by the claims administrator. BP intends to pursue all available legal options, including rights of appeal, to challenge this ruling. Given the inherent uncertainty that exists as BP pursues all available legal options to challenge the recent ruling, and the higher number of claims received and higher average claims payments than previously assumed by BP, which may or may not continue, management has concluded that no reliable estimate can be made of the cost of any business economic loss claims not yet received or processed by the DHCSSP. As a consequence, an amount of $0.8 billion previously provided for such claims has been derecognized. A provision will be re-established when a reliable estimate can be made of the liability. For further information see Financial statements – Note 36 on page 235, Note 43 on page 253 and Risk factors on pages 38-44.

BP's current estimate of the total cost of those elements of the PSC settlement that can be estimated reliably, which excludes any future business economic loss claims not yet received or processed by the DHCSSP, is $7.7 billion. If BP is successful in its challenge to the court's ruling, the total estimated cost of the settlement agreement will, nevertheless, be significantly higher than the current estimate of $7.7 billion, because business economic loss claims not yet received or processed are not reflected in the current estimate and the average payments per claim determined so far are higher than anticipated. If BP is not successful in its challenge to the court's ruling, a further significant increase to the total estimated cost of the settlement will be required. However, there can be no certainty as to how the dispute will ultimately be resolved or determined. To the extent that there are insufficient funds available in the Trust fund, payments under the PSC settlement will be made by BP directly, and charged to the income statement.

Significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable through the claims process. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported. In addition, there is further uncertainty in relation to interpretations of the claims administrator regarding the protocols under the settlement agreement and judicial interpretation of these protocols, and the outcomes of any further litigation including in relation to potential opt-outs from the settlement or otherwise. The PSC settlement is uncapped except for economic loss claims related to the Gulf seafood industry. See Risk factors on pages 41-42, Financial statements – Note 2 on page 194, Note 36 on page 235 and Note 43 on page 253 for further information.

Claims under the Oil Pollution Act of 1990

On 4 June 2012, the BP claims programme also began accepting claims under the Oil Pollution Act of 1990 (OPA 90). The programme is open to claimants that wish to file economic and property damages claims and fall into one of three categories: individuals and businesses that are not class members; individuals and businesses that are class members, but exercise their legal right to opt out of the class settlement; and individuals and businesses that are class members but wish to pursue claims that are expressly reserved to them pursuant to the PSC settlement, to the extent such claims may fall within OPA 90.

Claims payments

By the end of 2012, BP had paid a total of $8.2 billion to individual and business claimants, including payments from the DHCSSP, the Gulf Coast Claims Facility, the BP claims programmes and the court-supervised transitional claims programme. In 2012, $1.9 billion was paid to individuals and businesses through the various programmes.

BP is also responsible for directly managing claims and funding requests for losses or expenses incurred by states, parishes, counties, federally recognized Indian tribes and other government entities. These government claims primarily cover costs associated with response and removal activities, increased public services and loss of revenues due to the accident.

Government entities have received approximately $1.4 billion in payments for claims, advances, and settlements.

Supporting recovery of the tourism and seafood industries

To support tourism in the affected states, BP has committed $179 million by the end of 2013 to Alabama, Florida, Louisiana and Mississippi for regional and national tourism promotion campaigns. To date, tourism organizations have received $173 million and are using the BP funds in part to expand their advertising and marketing efforts to reach potential visitors. State and regional tourism organizations reported strong visitor numbers across the affected states in 2012.

In addition to resolving legitimate claims made by those in the fishing and seafood processing industries, by the end of 2012 BP had paid or committed to pay $82 million to Alabama, Florida, Louisiana and Mississippi for state-led seafood testing and marketing programmes.

A further $57 million is being given to non-profit groups and government entities to promote the tourism and seafood industries as part of the PSC settlement.

Although research and monitoring continues, a number of experts believe the Gulf of Mexico seafood industry is making a strong recovery. Government testing results have led state and federal officials to declare that Gulf seafood is safe to consume. Government landings and abundance data show that Gulf seafood generally is within pre-spill landings and population trends in most areas in the northern Gulf. According to a September 2012 report from the National Oceanic and Atmospheric Administration (NOAA), 2011 commercial seafood landings in the Gulf reached their highest levels since 1999, although the results varied by state and by species.

Agreement with the US government

On 15 November 2012, BP Exploration & Production Inc. (BPXP) reached an agreement with the US government to resolve all federal criminal claims arising out of the Deepwater Horizon accident, spill, and response. On 29 January 2013, the US District Court for the Eastern District of Louisiana accepted BPXP's pleas and sentenced BPXP in accordance with the criminal plea agreement. Under the terms of the criminal plea agreement, BPXP pleaded guilty to 11 felony counts of Misconduct or Neglect of Ships Officers relating to the loss of 11 lives; one misdemeanour count under the Clean Water Act; one misdemeanour count under the Migratory Bird Treaty Act; and one felony count of obstruction of Congress. As part of the resolution of federal criminal claims, BPXP will pay $4 billion, including $1.256 billion in criminal fines, in instalments over a period of five years. Under the terms of the criminal plea agreement, a total of $2.394 billion will be paid to the National Fish & Wildlife Foundation (NFWF) over a period of five years. In addition, $350 million will be paid to the National Academy of Sciences (NAS) over a period of five years. The court also ordered, as previously agreed with the US government, that BPXP serve a term of five years' probation.

Also on 15 November 2012, BP reached a settlement with the US Securities and Exchange Commission (SEC), resolving the SEC's Deepwater Horizon-related civil claims against the company under Sections 10(b) and 13(a) of the Securities Exchange Act of 1934 and the associated rules. BP has agreed to a civil penalty of $525 million, payable in three instalments over a period of three years, and has consented to the entry of an injunction prohibiting it from violating certain US securities laws and regulations. The SEC's claims are premised on oil flow rate estimates contained in three reports provided by BP to the SEC during a period from 29 April 2010 to 4 May 2010, within the first 14 days after the accident. The settlement was approved by the US District Court for the Eastern District of Louisiana on 10 December 2012, and BP made its first payment of $175 million on 11 December 2012.

Under US law, companies convicted of certain criminal acts are subject to debarment from contracting with the federal government. The charges to which BPXP pleaded guilty included one misdemeanour count under the Clean Water Act which, by operation of law following the court's acceptance of BPXP's plea, triggers a statutory debarment, also referred to as mandatory debarment, of the BPXP facility where the Clean Water Act violation occurred.

On 1 February 2013, the EPA issued a notice that BPXP was mandatorily debarred at its Houston headquarters. Mandatory debarment prevents BPXP from entering into new contracts or new leases with the US government. A mandatory debarment does not affect any existing contracts or leases a company has with the US government and will remain in place until such time as the debarment is lifted through an agreement with the EPA.

On 28 November 2012, the EPA notified BP that it had temporarily suspended BP p.l.c., BPXP and a number of other BP subsidiaries from participating in new federal contracts. As a result of the temporary suspension, the BP entities listed in the notice are ineligible to receive any US government contracts either through the award of a new contract, or the extension of the term of, or renewal of, an expiring contract. The suspension does not affect existing contracts the company has with the US government, including those relating to current and ongoing drilling and production operations in the Gulf of Mexico.

With respect to the entities named in the temporary suspension, the temporary suspension may be maintained or the EPA may elect to issue a notice of proposed discretionary debarment to some or all of the named entities. Like suspension, a discretionary debarment would preclude BP entities listed in the notice from receiving new federal fuel contracts, as well as new oil and gas leases, although existing contracts and leases will continue. Discretionary debarment typically lasts three to five years, and may be imposed for a longer period, unless it is resolved through an administrative agreement.

While BP's discussions with the EPA have been taking place in parallel to the court proceedings on the criminal plea, the company's work towards reaching an administrative agreement with the EPA is a separate process, and it may take some time to resolve issues relating to such an agreement. BPXP's mandatory debarment applies following sentencing and is not an indication of any change in the status of discussions with the EPA. The process for resolving both mandatory and discretionary debarment is essentially the same as for resolving the temporary suspension. BP continues to work with the EPA in preparing an administrative agreement that will resolve suspension and debarment issues.

For further details, see Legal proceedings on pages 162-169.

Environmental restoration

We continued to support and participate in the Natural Resource Damages Assessment (NRDA) process and made progress in 2012 in a number of key areas as part of the ongoing effort to assess and address injury to natural resources in the Gulf of Mexico.

Natural resource damages assessment

Since May 2010, more than 200 initial and amended work plans have been developed to study resources and habitat by state and federal trustees and BP, and by the end of 2012 BP had paid $973 million to support the assessment process, including co-operative and independent studies. The study data will inform an assessment of injury to the Gulf Coast natural resources and the development of a restoration plan to mitigate the identified injuries. Detailed analysis and interpretation continue on the data that have been collected.

Scientists are studying a range of species, including marine mammals, birds, fish and plants to understand how wildlife populations may have been affected by the accident. Teams of experts are also studying habitats such as wetlands and beaches, with the goal of returning these resources to their baseline condition – the condition they would be in if the Deepwater Horizon accident had not occurred. In addition, experts are looking at how recreational uses of natural resources may have been affected so that lost opportunities to enjoy those activities can be addressed through restoration.

Early restoration projects

In 2012, work began on the initial set of early restoration projects identified through an agreement BP signed with state and federal trustees in April 2011. The trustees also approved two new early restoration projects in December 2012, which are designed to improve nesting habitat for birds and loggerhead sea turtles on a number of Gulf Coast beaches.

Under the early restoration framework agreement, BP agreed to fund up to $1 billion in early restoration projects to accelerate efforts to restore natural resources injured as a result of the Deepwater Horizon accident. The framework requires BP and the trustees to agree on the potential projects, funding and the natural resources benefits the projects are expected to provide. The trustees will then implement the projects.

The agreement between BP and the trustees makes it possible for restoration to begin at an earlier stage of the NRDA process than usual. Natural Resource Damages (NRD) restoration projects are typically funded only after the NRD assessment is complete and a final settlement has been reached or a final court judgment has been entered. This process often takes many years, and restoration is often delayed during that time. The early restoration framework agreement allows the parties to expedite projects to restore, replace or acquire the equivalent of injured natural resources in the Gulf soon after an injury is identified, reducing the time needed to achieve restoration of those resources.

BP committed to fund the estimated $60 million cost of the eight initial early restoration projects that were approved by the trustees in April 2012 following public review and comment. The eight projects will collectively restore and enhance wildlife, habitats, the ecosystem services provided by those habitats, and provide additional access for fishing, boating and related recreational uses. Funding will come from the $20-billion Trust.

Following a 30-day public comment period, the trustees approved on 21 December 2012 the two new projects to improve habitat for nesting birds and sea turtles that will cost an additional estimated $9 million. The trustees and BP are working to identify additional projects for public review and comment. More information about the status of early restoration can be found on the NOAA website.

Sharing the information

In 2012 BP produced a second progress report on the NRDA effort and made presentations at scientific conferences to describe studies that are under way. The trustees have already made some of the data sets from these studies available online while others are still being finalized. BP seeks to share data and information collected from the co-operative NRDA studies with stakeholders and members of the public once these have been approved for release by the trustees.

Supporting the Gulf of Mexico Research Initiative

BP has committed $500 million over 10 years to fund independent scientific research through the Gulf of Mexico Research Initiative. The goal of the research initiative is to improve society's ability to understand, respond to and mitigate the potential impacts of oil spills to marine and coastal ecosystems. Through a competitive review process, the initiative approved funding in August 2012 for 19 grants that will provide approximately $20 million to researchers over the next three years. Including funding awarded in 2010 and 2011, the total funding awarded by the end of 2012 was $184 million. Grant recipients are investigating the fate of oil releases; the ecological and human health aspects of spills; and the development of new tools and technology for future spill response, mitigation and restoration.

Financial update

The group income statement for 2012 includes a pre-tax charge of $5.0 billion in relation to the Gulf of Mexico oil spill. The charge for the year reflects the agreement with the US government, adjustments to provisions and the ongoing costs of the Gulf Coast Restoration Organization. As at 31 December 2012, the total cumulative charge recognized to date for the accident amounts to $42.2 billion.

The cumulative income statement charge does not include amounts for obligations that BP considers are not possible, at this time, to measure reliably. The total amounts that will ultimately be paid by BP in relation to all the obligations relating to the accident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors, as discussed under Contingent liabilities in Note 43 on page 253, including in relation to any new information or future developments. These could have a material impact on our consolidated financial position, results of operations and cash flows. The risks associated with the accident could also heighten the impact of the other risks to which the group is exposed, as further described under Risk factors on pages 38-44.

For details regarding the impacts and uncertainties relating to the Gulf of Mexico oil spill refer to Financial statements – Note 2 on page 194, Note 36 on page 235 and Note 43 on page 253. See also Proceedings and investigations relating to the Gulf of Mexico oil spill on pages 59-62.

Trust update

BP, in agreement with the US government, set up the $20-billion Deepwater Horizon Oil Spill Trust (the Trust) to provide confidence that funds would be available to satisfy individual and business claims, final judgments in litigation and litigation settlements, state and local response costs and claims, and natural resource damages and related costs.

BP contributed a total of $4.9 billion to the Trust in 2012. The Trust has now been fully funded. Payments made during 2012 were $2.8 billion for individual and business claims, medical settlement programme payments, NRD assessment and early restoration, state and local government claims, DHCSSP expenses and other resolved items. These payments were made from the Trust and qualified settlement funds (QSFs) established for paying the costs of the settlement agreements with the PSC and funded by the Trust. An additional $1.8 billion was paid from the Trust into the $2.3-billion seafood compensation fund, extinguishing BP's liability, which had not yet been paid to claimants. As at 31 December 2012, the cumulative amount paid from the Trust and QSFs since inception was $9.5 billion, and the remaining cash balance was $10.5 billion, including $1.8 billion remaining in the seafood compensation fund.

As at 31 December 2012, the cumulative charges for provisions to be paid from the Trust and the associated reimbursement asset recognized amounted to $17.8 billion. The increased charges in 2012 reflect higher provision estimates for claims paid prior to establishing the DHCSSP, claims and administration costs of the DHCSSP and NRD assessment costs. A further $2.2 billion could be provided in subsequent periods for items covered by the Trust, with no net impact on the income statement. The amount of cumulative charges for provisions described above will increase as more information becomes available, the interpretation of the protocols established in the economic and property damages settlement agreement is clarified and the claims process matures, enabling BP to estimate reliably the cost of claims which currently cannot be estimated reliably and are therefore not provided for. See Plaintiffs' Steering Committee settlements on page 60 and Financial statements – Note 36 on page 235 for further information.

Legal proceedings and investigations

On 25 February 2013, the first phase of a Trial of Liability, Limitation, Exoneration and Fault Allocation commenced in the federal multi-district litigation proceeding in New Orleans. For further information on this and other legal proceedings, see pages 162-169.

Upstream

In 2012 we continued to actively manage and simplify our portfolio, strengthening our incumbent positions to provide a platform for growth in the future.

What we do

We are focused on accessing and extracting oil and gas through all stages of the life cycle and we deliver these activities through three separate divisions:

Exploration – responsible for renewing our resource base through access, exploration and appraisal.

Developments – ensures the safe, reliable and compliant execution of wells (drilling and completions) and major projects and comprises the global wells organization and the global projects organization.

Production – ensures safe, reliable and compliant operations, including upstream production assets, midstream transportation and processing activities, and the development of our resource base.

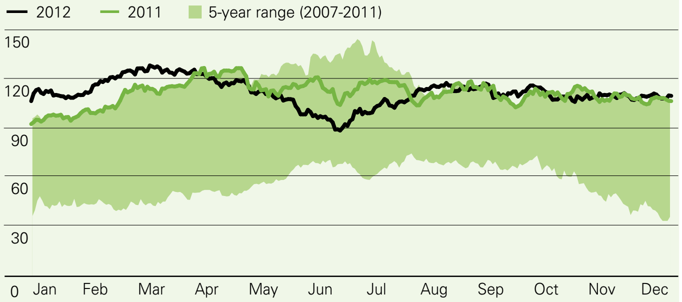
These activities are optimized and integrated with support from global functions with specialist areas of expertise and the group's strategy and integration organization, which comprises finance, procurement and supply chain, human resources, technology and information technology.

Our Upstream segment includes upstream and midstream activities, and gas marketing and trading activities in 28 countries with production from 19 countries, see pages 6-7.

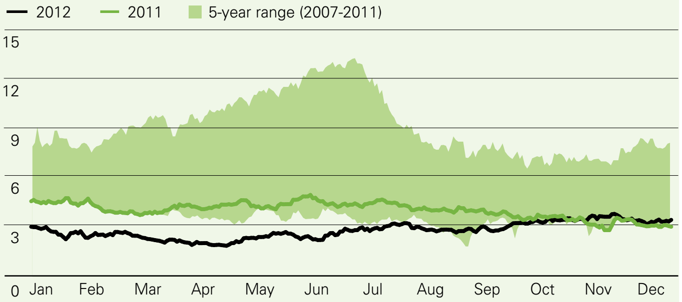
Our market – 2012 summary

- Growth in world oil consumption remains weak.
- Brent continued to be the main driver of oil price realizations; other principal local markers included West Texas Intermediate (WTI) and Alaska North Slope (ANS).
- Brent averaged $111.67 per barrel, similar to 2011's average of $111.26 per barrel.
- Continued divergence in natural gas prices with US Henry Hub First of Month Index falling 31% to average $2.79/mmBtu in 2012, while European spot prices increased.

Brent ($/bbl)



Henry Hub ($/mmBtu)



Our strategy

In Upstream, our highest priority is to ensure safe, reliable and compliant operations worldwide. Our strategy is to invest to grow long-term value by continuing to build a portfolio of material, enduring positions in the world's key hydrocarbon basins. Our strategy is enabled by:

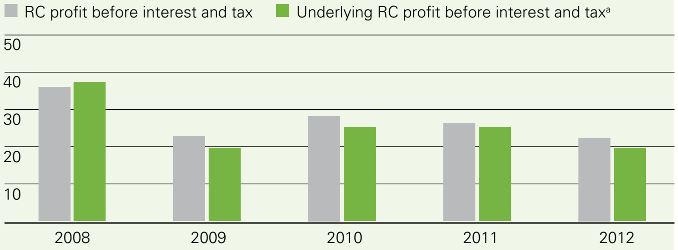
- A continued focus on safety and the systematic management of risk.
- Playing to our strengths – exploration, giant fields, deepwater and gas value chains.
- A simplified portfolio with strengthened incumbent positions and reduced operating complexity.
- An execution model that drives improvement in efficiency and reliability – through both operations and investment.
- A bias to oil while maintaining a balance of gas markets and resource types.
- Strong relationships built on mutual advantage, deep knowledge of the basins in which we operate, and technology.

We intend to gradually increase investment with a focus on exploration, a key source of value creation, and evolve the nature of our relationships, particularly with national oil companies.

Our performance – 2012 summary

- The safety metrics of day away from work case frequency and loss of primary containment improved compared with 2011 (see page 64).
- In 2012 replacement cost profit before interest and tax for the segment was $22.5 billion, compared with $26.4 billion in 2011. After adjusting for non-operating items and fair value accounting effects, underlying replacement cost profit[a] before interest and tax in 2012 was $19.4 billion compared with $25.2 billion for the previous year (see page 65).
- Our exploration division gained access to potential new resources in six countries, covering more than 68,000km^2 in 2012.
- In 2012 there were five major upstream project start-ups.
- Disposal transactions generated $10.7 billion in proceeds in 2012.

Upstream profitability ($ billion)



Outlook

- In 2013 we expect reported production to be lower than 2012, mainly due to the impact of divestments which we estimate at around 150mboe/d. After adjusting for the impacts of divestments and entitlement effects in our PSAs, we expect underlying production to grow.
- We expect four major projects to come onstream towards the end of 2013, with a further six in 2014.
- We expect to make the final investment decision (FID) on five projects in 2013.
- Capital investment in 2013 will increase, reflecting the progression of our major projects and the increases in exploration and access activity.
- We remain on track to deliver Upstream's contribution to the group's plan to generate an increase of around 50% in operating cash flow by 2014 compared with 2011.[b]

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[a] Underlying replacement cost profit before interest and tax is not a recognized GAAP measure. See footnote b on page 34 for further information. The equivalent measure on an IFRS basis is replacement cost profit before interest and tax.

[b] See footnote c on page 21.

With effect from 1 January 2012, the Exploration and Production segment was split to form two new operating segments, Upstream and TNK-BP, reflecting the way in which we were managing our investment in TNK-BP. Comparative data has been restated to reflect this change. For information on our subsequent agreement to sell our interest in TNK-BP to Rosneft, see pages 80-81.

Market commentary

The growth in world oil consumption remained weak in 2012, with continued growth in China and other non-OECD countries offsetting yet another decline in OECD countries. With oil markets balancing supply losses against weak consumption and high OPEC production, average crude oil prices in 2012 were similar to the previous year. Natural gas prices continued to show divergence amongst markets globally in 2012.

	2012	2011	2010
Average oil marker prices[a]			$ per barrel
West Texas Intermediate	**94.13**	95.04	79.45
Brent	**111.67**	111.26	79.50
Average natural gas marker prices			$ per million British thermal units
Average Henry Hub gas price[b]	**2.79**	4.04	4.39
			pence per therm
Average UK National Balancing Point gas price[a]	**59.74**	56.33	42.45

[a] All traded days average.
[b] Henry Hub First of Month Index.

Crude oil prices

Crude oil prices, as demonstrated by the industry benchmark of dated Brent for the year, averaged $111.67 per barrel in 2012, similar to the 2011 average of $111.26 per barrel. This represented the highest annual average ever (in nominal terms).

Brent remains an integral marker to the production portfolio with a significant proportion of production being priced directly or indirectly from this. Certain regions use other local markers, which are derived using differentials, premiums or a lagged impact from the Brent crude oil price.

Prices rose early in 2012 due to concerns about risks to supply stemming from the stand-off over Iran's nuclear programme, with prices reaching a peak of $128 per barrel in March. Thereafter, weaker economic growth, high OPEC production and rising OECD commercial inventories pushed oil prices to a low of $89 per barrel in June, before better economic news, a substantial reduction in Iranian production, and renewed concerns about risks to supply drove a recovery in prices.

Against this backdrop of a weak economy and high oil prices, global oil consumption remained weak, rising by roughly 1 million barrels per day for the year (1.1%)[a]. Growth in 2012 was once again led by non-OECD countries including China. OECD consumption fell for the sixth time in the past seven years. Non-OPEC production rose slightly, with strong US growth offset by declines elsewhere. OPEC crude oil production remained robust despite a large decline in Iranian output due to US and EU sanctions. As a result, OECD commercial oil inventories rose above average in late 2012.

By comparison, global oil consumption in 2011 grew by roughly 0.6 million barrels per day (0.7%)[b]. OPEC production met the growth in consumption despite the disruption of Libyan production due to large increases in Saudi Arabia and other Middle-Eastern producers, but the loss of production drove oil prices sharply higher.

We expect oil price movements in 2013 to continue to be driven by the pace of global economic growth and its resulting implications for oil consumption, by the supply growth in North America, and OPEC production decisions. The path of Iranian production in the face of ongoing US and EU sanctions remains a key uncertainty.

Natural gas prices

Natural gas prices continued to diverge globally in 2012. The average US Henry Hub First of Month Index fell 31% to average $2.79/mmBtu in 2012, while European spot prices increased. In Upstream, with the exception of our North American gas business, a significant amount of our gas production is based on long-term contracts with fixed prices, meaning that market fluctuations have less of an impact on our revenues.

The US gas market in 2012 was dominated by an unusually warm winter at the start of the year, causing a collapse of heating demand. Spot prices fell to 10-year lows, promoting an unprecedented coal-to-gas switch in power generation, and a slowdown in gas drilling activity. Together with an unusually warm summer, boosting electricity demand for air-conditioning, these short-run market responses led to a modest recovery in US prices, which was stalled by a return to an unusually warm December towards the end of 2012.

In Europe, spot gas prices at the UK National Balancing Point increased by 6% to an average of 59.74 pence per therm for 2012. This increase came despite weak demand in European gas markets, due to the economic turmoil in Europe and gas being uncompetitive in power generation relative to coal. European spot prices were supported by the tight global LNG market as strong demand and high spot prices in Asia, driven by Japan's need for LNG to replace lost nuclear power and cover demand during an unusually cold December in 2012, continued to attract LNG away from Europe. LNG deliveries to Europe in 2012 were 23% lower than in 2011.

In 2011, compared with 2010, the strength of shale gas production growth had led the average Henry Hub First of Month Index to weaken, falling by 8% to $4.04/mmBtu. In the UK, National Balancing Point prices averaged 56.33 pence per therm, 33% above prices in 2010.

In 2013, we expect gas markets to continue to be driven by the economy, weather, domestic production, limited increases in LNG supplies and continuation of the uncertainty surrounding nuclear power generation in Japan. Futures markets indicate that the large gap between US and European gas prices is expected to persist through 2013.

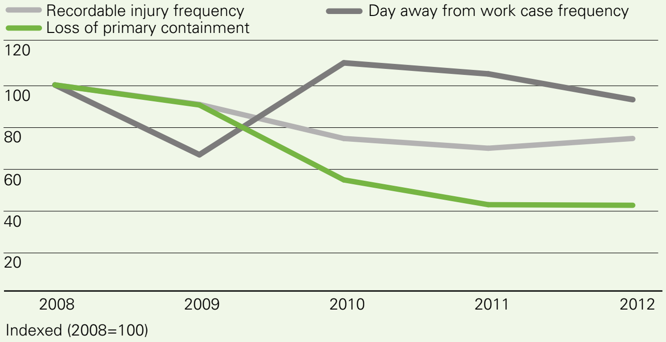
2012 performance

Safety performance

In Upstream, delivering safe, reliable and compliant operations remains our highest priority. The group safety and operational risk (S&OR) function supports the business line in delivering safe, reliable and compliant operations across the group's operated businesses. S&OR staff are deployed at the operating level throughout the Upstream segment to support the systematic and disciplined application of those standards. This creates an independent reporting line, working alongside line management while having the power to intervene, supported by a systematic framework provided by BP's operating management system (OMS). All upstream operated businesses are applying OMS to govern BP operations and continue to work to achieve conformance to standards and practices required by OMS through the performance improvement cycle process. We continue to work to enhance local systems and processes at all our sites. See Safety on pages 46-50 for more information on OMS.

Safety performance is monitored by a suite of input and output metrics that focus on personal and process safety including operational integrity, occupational health and legal compliance.

Key safety metrics 2008-2012
(number of incidents)



In 2012 there was one workforce fatality in Upstream. In 2011, there were no workforce fatalities.

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[a] From *Oil Market Report 18 January 2013*©, OECD/IEA 2013, page 4.
[b] *BP Statistical Review of World Energy June 2012.*

The recordable injury frequency (RIF), which measures the number of recordable injuries to the BP workforce per 200,000 hours worked, was 0.32. This is higher than 2011 when it was 0.30 and equal to 2010 when it was also 0.32. The 2012 DAFWCF, a subset of the RIF that measures the number of cases where an employee misses one or more days from work per 200,000 hours worked, was 0.053. This is lower than 2011 when it was 0.060 and 2010 when it was 0.063.

In 2012 the number of reported loss of primary containment (LOPC) incidents in Upstream was 151, down from 152 in 2011. The number of reported oil spills equal to or larger than 1 barrel during 2012 was 87, up from 71 in 2011.

Financial and operating performance

			$ million
	2012	2011	2010
Sales and other operating revenues[a]	**71,940**	75,475	66,266
Replacement cost profit before interest and tax	**22,474**	26,366	28,269
Net (favourable) unfavourable impact of non-operating items and fair value accounting effects[b]	**(3,055)**	(1,141)	(3,196)
Underlying replacement cost profit before interest and tax[c]	**19,419**	25,225	25,073
Capital expenditure and acquisitions	**17,859**	25,535	17,753
BP average realizations[d]			$ per barrel
Crude oil	**108.94**	107.91	77.54
Natural gas liquids	**42.75**	51.18	42.78
Liquids[e]	**102.10**	101.29	73.41
			$ per thousand cubic feet
Natural gas	**4.75**	4.69	3.97
US natural gas	**2.32**	3.34	3.88
			$ per thousand barrels of oil equivalent
Total hydrocarbons[f]	**61.86**	62.31	47.90
Production (net of royalties)[g]			
Liquids[e]			thousand barrels per day
Subsidiaries	**896**	992	1,228
Equity-accounted entities	**284**	294	289
Total of subsidiaries and equity-accounted entities	**1,179**	1,285	1,517
Natural gas			million cubic feet per day
Subsidiaries	**6,193**	6,393	7,332
Equity-accounted entities	**416**	415	429
Total of subsidiaries and equity-accounted entities	**6,609**	6,807	7,761
Total hydrocarbons[f]			thousand barrels of oil equivalent per day
Subsidiaries	**1,963**	2,094	2,492
Equity-accounted entities	**355**	366	363
Total of subsidiaries and equity-accounted entities	**2,319**	2,460	2,855

[a] Includes sales between businesses.

[b] Fair value accounting effects represent the (favourable) unfavourable impact relative to management's measure of performance (see page 37 for further details).

[c] Underlying replacement cost profit is not a recognized GAAP measure. See footnote b on page 34 for information on underlying replacement cost profit.

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

[e] Liquids comprise crude oil, condensate and natural gas liquids (NGLs).

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

[g] Includes BP's share of production of equity-accounted entities in the Upstream segment.

Because of rounding, some totals may not agree exactly with the sum of their component parts.

			$ million
	2012	2011	2010
Estimated net proved reserves (net of royalties)			
Liquids[h]			million barrels
Subsidiaries[i]	**4,477**	5,154	5,558
Equity-accounted entities[j]	**838**	929	1,221
Equity-accounted entities (bitumen)[j]	**195**	178	179
Total of subsidiaries and equity-accounted entities	**5,510**	6,261	6,958
Natural gas			billion cubic feet
Subsidiaries[k]	**33,264**	36,380	37,809
Equity-accounted entities[j]	**2,549**	2,397	2,532
Total of subsidiaries and equity-accounted entities	**35,813**	38,777	40,341
Total hydrocarbons			million barrels of oil equivalent
Subsidiaries	**10,213**	11,426	12,077
Equity-accounted entities	**1,472**	1,520	1,837
Total of subsidiaries and equity-accounted entities	**11,685**	12,946	13,914

[h] Liquids comprise crude oil, condensate, NGLs and bitumen.

[i] Includes 14 million barrels (20 million barrels at 31 December 2011 and 22 million barrels at 31 December 2010) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[j] During 2012, upstream operations in Abu Dhabi, Argentina and Bolivia, as well as some of our operations in Angola, Canada, Indonesia and Trinidad, were conducted through equity-accounted entities.

[k] Includes 2,890 billion cubic feet of natural gas (2,759 billion cubic feet at 31 December 2011 and 2,921 billion cubic feet at 31 December 2010) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

Sales and other operating revenues for 2012 were $72 billion, compared with $75 billion in 2011 and $66 billion in 2010. The decrease in 2012, compared with 2011, primarily reflected lower production and persistently low Henry Hub gas prices. The increase in 2011, compared with 2010, primarily reflected higher oil and gas realizations, partly offset by lower production.

The replacement cost profit before interest and tax for 2012 was $22,474 million, compared with $26,366 million for the previous year. This included net non-operating gains of $3,189 million, primarily a result of gains on disposals being partly offset by impairment charges. (See page 37 for further information on non-operating items.) In addition, fair value accounting effects had an unfavourable impact of $134 million relative to management's measure of performance. (See page 37 for further information on fair value accounting effects.)

After adjusting for non-operating items and fair value accounting effects, the underlying replacement cost profit in 2012 was $19,419 million, compared with $25,225 million in 2011. The 23% decrease was due to higher costs (primarily higher depreciation, depletion and amortization, as well as ongoing sector inflation), lower production and lower realizations.

Total capital expenditure including acquisitions and asset exchanges in 2012 was $17.9 billion (2011 $25.5 billion and 2010 $17.8 billion). (See page 66 for further information on acquisitions.)

Provisions for decommissioning increased from $17.2 billion at the end of 2011 to $17.3 billion at the end of 2012. The increase reflects updated estimates of the cost of future decommissioning and additions for new assets, largely offset by transfers to assets held for sale and divestments. Decommissioning costs are initially capitalized within fixed assets and are subsequently depreciated as part of the asset.

Prior years' comparative financial information

The replacement cost profit before interest and tax for the year ended 31 December 2011 of $26,366 million included net non-operating gains of $1,130 million, primarily a result of gains on disposals being partly offset by impairments, a charge associated with the termination of our agreement to sell our 60% interest in Pan American Energy LLC (PAE) to Bridas Corporation and other non-operating items. In addition, fair value accounting effects had a favourable impact of $11 million relative to management's measure of performance.

The replacement cost profit before interest and tax for the year ended 31 December 2010 of $28,269 million included net non-operating gains of $3,199 million, comprised primarily of gains on disposals that completed during the year partly offset by impairment charges and fair value losses on embedded derivatives. In addition, fair value accounting effects had an unfavourable impact of $3 million relative to management's measure of performance.

After adjusting for non-operating items and fair value accounting effects, the underlying replacement cost profit in 2011 compared with 2010 was marginally increased, reflecting higher realizations partially offset by lower production volumes (including in higher margin areas).

Acquisitions and disposals

During 2012 we undertook a number of disposals. In total, disposal transactions generated $10.7 billion in proceeds during 2012. With regards to proved reserves, 441mmboe net were disposed of, all within our subsidiaries. There were no significant acquisitions in 2012.

Disposals

- On 28 February 2012 BP announced it had agreed terms with LINN Energy to sell BP's Hugoton basin assets (including the Jayhawk NGL plant). Under the agreement LINN Energy agreed to pay BP $1.2 billion in cash. The sale completed on 30 March 2012.
- On 27 March 2012 BP announced that it had agreed to sell its interests in all of its operated gas fields in the southern North Sea, including associated pipeline infrastructure and the Dimlington terminal (including the integrated Easington terminal) to Perenco UK Ltd for $400 million. The sale completed in October 2012.
- On 2 April 2012 the sale of the Canadian natural gas liquid business to Plains Midstream Canada ULC, a wholly owned subsidiary of Plains All American Pipeline L.P., announced in 2011, was completed.
- On 25 June 2012 BP announced that it had agreed to sell its interests in the Jonah and Pinedale upstream operation in Wyoming to LINN Energy for $1.025 billion. The sale completed on 31 July 2012.
- On 26 June 2012 BP announced that it had agreed to sell its non-operated interests in the Alba and Britannia fields in the UK North Sea to Mitsui & Co Ltd for $280 million. The sale completed in December 2012.
- On 10 August 2012 BP announced that it had agreed to sell its Sunray and Hemphill gas processing plants in Texas, together with their associated gas gathering system, to Eagle Rock Energy Partners for $228 million. The sale completed on 1 October 2012.
- On 10 September 2012 BP announced that it had agreed to sell its interests in a number of non-strategic assets in the Gulf of Mexico to Plains Exploration and Production Company for $5.55 billion. The sale includes interests in three BP-operated assets: the Marlin hub, comprised of the Marlin, Dorado and King fields (BP 100%); Horn Mountain (BP 100%) and Holstein (BP 50%). The deal also includes BP's stake in two non-operated assets: Ram Powell (BP 31%) and Diana Hoover (BP 33.33%). The sale completed on 30 November 2012.
- On 13 September 2012 BP announced that it had agreed to sell its 18.36% non-operated interest in the Draugen field in the Norwegian Sea to AS Norske Shell for $240 million in cash. The sale completed in November 2012.
- On 28 November 2012 BP announced that it had agreed to sell a package of its central North Sea assets to TAQA Bratani Ltd for up to $1.3 billion (comprising $1.058 billion consideration plus future payments which, dependent on oil price and production, are expected to exceed $250 million after tax). This package comprised the non-operated Braes and Braemar assets, and the operated Harding, Maclure and Devenick assets. The transaction is subject to third-party and regulatory approvals.
- On 17 December 2012 BP announced that it had agreed to sell its 50% non-operated interest in the Sean field in the UK North Sea to SSE PLC for $288 million in cash. The transaction is subject to third-party and regulatory approvals.
- On 19 December 2012 BP announced that it had agreed the sale of its 34.3% interest in the Yacheng gas field in the South China Sea to Kuwait Foreign Petroleum Exploration Company (KUFPEC) for $308 million in cash. The transaction is subject to regulatory, CNOOC and third-party approvals.
- BP's 33.3% ownership in the Phu My 3 power business in Vietnam was originally part of the divestment programme of the integrated gas business to TNK-BP. However, the Phu My 3 part of the divestment failed to conclude prior to the expiry of the sale and purchase agreement, and hence was reclassified from being held for sale into routine business. BP is open to other future divestment options and is currently evaluating its position in the business over the medium term.

Exploration

We continually seek access to resources and in 2012 this included Brazil, where we farmed in to four deepwater concessions covering 2,100km^2 on the Equatorial Margin; Canada, where we were the successful bidder on four leases, covering almost 14,000km^2 offshore Nova Scotia, for which award is expected to be completed in early 2013; Egypt, where we farmed in to two blocks covering 1,400km^2; deepwater Gulf of Mexico, where we were assigned 51 leases covering 1,200km^2; Namibia, where we farmed in to five deepwater blocks covering 22,900km^2; Uruguay, where we signed three production sharing agreements (PSAs) for deepwater exploration blocks covering almost 26,000km^2; and the onshore US, where we signed an agreement to lease 300km^2 in the Utica/Point Pleasant shale formation in Ohio.

Our exploration and appraisal programme is currently active in Algeria, Angola, Australia, Azerbaijan, Brazil, Canada, Egypt, the deepwater Gulf of Mexico, Jordan, Namibia, Trinidad, the UK North Sea, Oman and onshore US.

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.

In 2012 our exploration and appraisal costs, excluding lease acquisitions, were $4,317 million, compared with $2,398 million in 2011 and $2,706 million in 2010. These costs included exploration and appraisal drilling expenditures, which were capitalized within intangible fixed assets, and geological and geophysical exploration costs, which were charged to income as incurred. Approximately 58% of 2012 exploration and appraisal costs were directed towards appraisal activity. In 2012, we participated in 177 gross (46.2 net) exploration and appraisal wells in eight countries.

Total exploration expense in 2012 of $1,475 million (2011 $1,520 million and 2010 $843 million) included the write-off of expenses related to unsuccessful drilling activities in the UK North Sea ($97 million), Namibia ($64 million) and others ($72 million). It also included $97 million related to decommissioning of idle infrastructure, as required by the Bureau of Ocean Energy Management Regulation and Enforcement's Notice of Lessees 2010 G05 issued in October 2010.

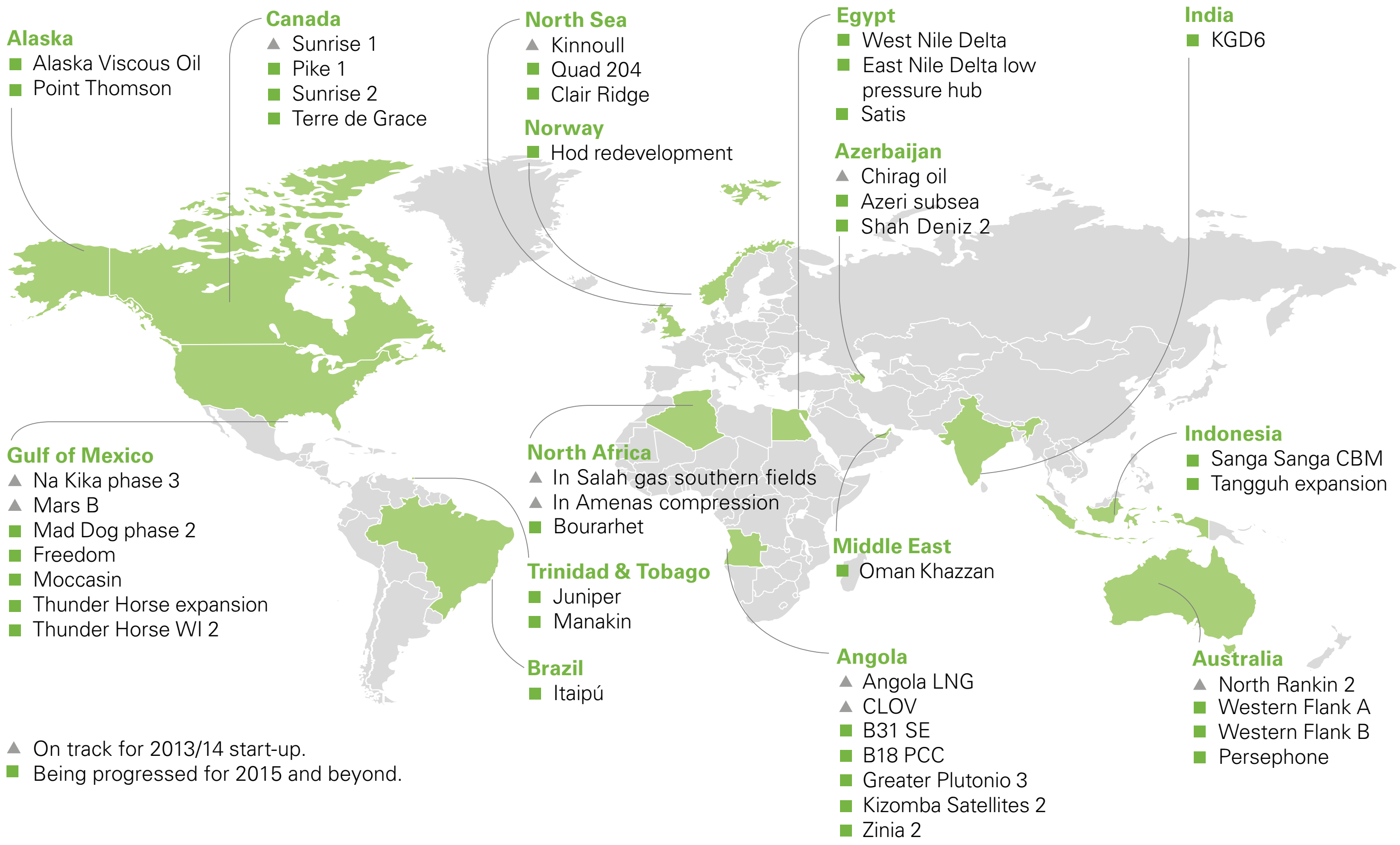
Reserves

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

The Upstream segment's total hydrocarbon reserves, on an oil equivalent basis including equity-accounted entities comprised 11,685mmboe (10,213mmboe for subsidiaries and 1,472mmboe for equity-accounted entities) at 31 December 2012, a decrease of 10% (decrease of 11% for subsidiaries and decrease of 3% for equity-accounted entities) compared with the 31 December 2011 reserves of 12,946mmboe (11,426mmboe for subsidiaries and 1,520mmboe for equity-accounted entities).

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. For 2012 the proved reserves replacement ratio for the Upstream segment, excluding acquisitions and disposals, was 6% for subsidiaries and equity-accounted entities, –5% for subsidiaries alone and 65% for

Major projects portfolio



equity-accounted entities alone. For more information on proved reserves replacement for the group, see pages 85-86.

Developments

In 2012 five major projects came onstream: Devenick in the North Sea; Skarv in the Norwegian Sea; Clochas Mavacola and the Plutão field, part of the Plutão, Saturno, Venus and Marte (PSVM) project in Angola; and Galapagos in the Gulf of Mexico. In November 2012 we announced the Savonette gas discovery offshore Trinidad.

We took final investment decisions on three projects: Juniper, Kizomba Satellites phase 2 and Point Thomson.

The map above shows our major development areas, which include Angola, Australia, Azerbaijan, Canada, Egypt, the deepwater Gulf of Mexico, North Africa and the UK North Sea. Development expenditure of subsidiaries incurred in 2012, excluding midstream activities, was $12.0 billion, compared with $10.2 billion in 2011 and $9.7 billion in 2010.

Production

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. The principal areas of production are Angola, Argentina, Azerbaijan, Egypt, Trinidad, the UAE, the UK and the US.

Our total hydrocarbon production during 2012 averaged 2,319 thousand barrels of oil equivalent per day (mboe/d). This comprised 1,963mboe/d for subsidiaries and 355mboe/d for equity-accounted entities, a decrease of 6% (decreases of 10% for liquids and 3% for gas) and a decrease of 3% (decrease of 3% for liquids and no change for gas) respectively compared with 2011. For subsidiaries, 34% of our production was in the US, 19% in Trinidad and 8% in the UK.

In aggregate, after adjusting for the impact of price movements on our entitlement to production in our PSAs and the effect of acquisitions and disposals, underlying production was broadly flat compared with 2011. This primarily reflects major project start-ups and improved operating performance in Angola, partly offset by natural field decline and the impact of turnaround and maintenance activities.

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 that are not subject to priorities, curtailments or other restrictions. No single contract or group of related contracts is material to the group.

Regional summary

The following discussion reviews operations in our upstream business by geographical area, and lists associated significant events. 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. Consequently, the percentages disclosed for certain agreements do not necessarily reflect the percentage interests in reserves and production.

Europe

In Europe, BP is active in the UK North Sea and the Norwegian Sea. Key aspects of our activities in the North Sea include a focus on in-field drilling and selected new field developments. We are the largest producer of hydrocarbons in the UK.

- On 16 November 2010, production from the Rhum gas field in the central North Sea was suspended following the imposition of EU sanctions on Iran. Rhum is owned by BP (50%) and the Iranian Oil Company (50%) under a joint operating agreement dating back to the early 1970s. Rhum remains shut-in. See Further note on certain activities on page 45 for further information.
- In October 2012 BP announced the start-up of the Devenick gas project in the central North Sea. It was subsequently announced in November

2012 that BP's interests in Devenick would form part of the package of central North Sea assets to be sold to TAQA Bratani Ltd along with the Braes and Braemar assets and the Harding and Maclure assets.

- In December 2012 BP announced that it had acquired Total's equity in the Mungo and Monan Fields for a cost of $155 million. The acquisition takes BP's ownership of Mungo and Monan from 69% to 82%.
- In December 2012 gas production from the Skarv field in the Norwegian Sea commenced. The new Skarv floating production storage and offloading vessel (FPSO) is expected to produce for 25 years and to be a key hub for BP in Norway, with production capabilities of 85,000 barrels per day of oil and 670 million standard cubic feet per day (mmcf/d) of gas. The vessel is built for adverse weather and is the most northerly operated FPSO in BP's portfolio.
- In January 2013 production from the new facilities at the Valhall field in the southern part of the Norwegian North Sea commenced. Production from Valhall is expected to build up to around 65,000 barrels of oil equivalent per day in the second half of 2013.

North America

Our upstream activities in North America take place in four main areas: deepwater Gulf of Mexico, Lower 48 states, Alaska and Canada. For further information on the activities of BP's Gulf Coast Restoration Organization established following the Deepwater Horizon oil spill, see pages 59-62. BP is one of the largest producers of hydrocarbons and the largest acreage holder in the deepwater Gulf of Mexico, operating four production hubs.

- In 2012 BP started up an additional two rigs in the Gulf of Mexico and by the end of the year had seven rigs operational. An eighth rig is in place on the Mad Dog platform and is expected to start up in 2013.
- BP was assigned 51 blocks in the deepwater Gulf of Mexico, 40 blocks from the 2012 central lease sale that took place in June 2012 and 11 blocks from the western lease sale which occurred in December 2011.
- In June 2012 BP announced the start-up of the Galapagos development in the deepwater Gulf of Mexico. The development includes the subsea tie-back to the BP operated Na Kika facility of three deepwater fields – Isabela, Santiago and Santa Cruz.

For information on the temporary suspension and mandatory debarment notices issued by the US Environmental Protection Agency (EPA) see Legal proceedings on page 163.

The US onshore business operates in the Lower 48 states producing natural gas, NGLs and condensate across nine states, including production from tight gas, coalbed methane (CBM) and shale gas assets. For further information on the use of hydraulic fracturing in our shale gas assets see pages 52-53.

- During 2012 the US lower 48 onshore gas business recognized impairment losses of $1,458 million primarily in the Woodford and Fayetteville shales reflecting reduced fair market values in the prevailing low price environment.
- In March 2012 BP announced it had signed an agreement to lease approximately 300 km^2 in northeast Ohio for future oil and gas production in the Utica/Point Pleasant shale formation. The agreement was signed with the Associated Landowners of the Ohio Valley (ALOV), a group representing area mineral owners.

In Alaska, we operate 13 North Slope oilfields (including Prudhoe Bay, Endicott, Northstar and Milne Point) and four North Slope pipelines, and own significant interests in six other producing fields.

- On 30 March 2012 BP, other Alaska North Slope producers, and the State of Alaska announced the settlement of a long-running legal dispute about the future development of the Point Thomson field. BP holds a 32% interest in the Point Thomson field and ExxonMobil is the operator. Under the terms of the settlement agreement, the working interest owners committed to an initial gas and condensate cycling project, with production start-up scheduled for May 2016. A significant portion of the cost of this initial project will be pre-investment for a full scale Point Thomson gas development project with production either to be sold in world markets via a major North Slope gas export project; or to be transported and injected into the main Prudhoe Bay reservoirs to increase oil recovery in the near term, and later reproduced and sold.
- Also on 30 March BP, ExxonMobil and ConocoPhillips jointly announced that they are working together on a plan aimed at commercializing the extensive natural gas resources on the North Slope of Alaska. The three companies, along with TransCanada, are assessing a potential LNG development project.
- In June 2012 BP took the decision to suspend the Liberty project in Alaska. The Liberty oil field is located approximately six miles offshore in the Beaufort Sea. In November 2010 BP made the decision to suspend on-site physical construction of the Liberty rig to conduct an extensive engineering review and evaluation of the rig design, materials, and key systems. In the course of this review it was determined that the rig would require significant changes and investment in order to meet BP standards, and that these were not viable. The decision to suspend the Liberty project resulted in an impairment of the construction-in-progress value totalling $1 billion in the second quarter of 2012. On 20 November BP filed a request for a five-year lease extension to pursue alternative development plans. On 31 December 2012 the US Bureau of Safety and Environmental Enforcement (BSEE) approved a two-year extension for the Liberty leases until 31 December 2014 to allow BP time to prepare and submit a new Liberty development plan. BSEE also advised that they will grant a further extension as necessary to accommodate the regulatory review, preparation, and issuance of the final Record of Decision by the agencies on the proposed development project.
- In November 2012 the last remaining claims related to the March and April 2006 leaks from the Prudhoe Bay Oil Transit Lines were resolved. On 31 March 2009 the State of Alaska filed a complaint seeking civil penalties and damages relating to these leaks. In December 2011, BP and the State of Alaska entered into a Dispute Resolution Agreement that provided for a $10-million payment attributable to the state's environmental and attorneys' fee claims, and binding arbitration of the state's claims for royalty income damages, if any, arising out of the 2006 oil spills and related production shut-ins and pipeline replacements. The arbitration panel issued its final award on 31 October 2012, which required BP to pay the state $245.7 million. After reimbursement from the other Prudhoe Bay owners, BP's net working interest share of the arbitration award and the other claims was $64.8 million and $2.6 million respectively. Payments to the state were made on 13 and 14 November 2012.

In Canada, BP is currently focused on oil sands development, and intends to use in situ steam-assisted gravity drainage (SAGD) technology. This uses the injection of steam into the reservoir to warm the bitumen so that it can flow to the surface through producing wells. We hold interests in three oil sands leases through the Sunrise Oil Sands and Terre de Grace partnerships and the Pike Oil Sands joint venture. In addition, we have significant exploration interests in the Canadian Beaufort Sea. In 2012 we were the successful bidder on four leases covering almost 14,000km^2 offshore Nova Scotia, for which award is expected to be completed in early 2013.

South America

In South America, BP has upstream activities in Brazil, Argentina, Bolivia, Chile, Uruguay and Trinidad & Tobago.

In Brazil, BP has interests in 14 exploration and production blocks: seven in the Campos basin, two in the Ceará basin, two in the Barreirinhas basin, one in the Camamu-Almada basin, and two onshore in the Parnaiba basin.

- In March 2012 BP announced that the Brazilian National Petroleum Agency (ANP) approved its farm in to four deepwater exploration and production concessions operated by Petróleo Brasileiro S.A. (Petrobras) in Brazil. BP has a 40% interest in each of the blocks, located in the Barreirinhas and Ceará basins, and together the blocks cover a total area of 2,113km^2.

In Argentina, Bolivia and Chile, BP conducts activity through PAE, an equity-accounted joint venture with Bridas Corporation in which BP has a 60% interest.

- On 24 January 2012 the Republic of Bolivia issued a press statement declaring its intent to nationalize PAE's interests in the Caipipendi Operations Contract. Nevertheless, no formal decision was issued or announced by the government, and no nationalization process has occurred.

- In 2012 production was impacted by the construction union (Los Dragones) strike in the Cerro Dragon field which commenced on 21 June. At the end of October an agreement was reached with the construction union and in November with the oil labour workers union at a national and provincial level. Operations have now resumed.

In Uruguay, BP confirmed in October 2012 that it had signed PSAs for three offshore deepwater exploration blocks. The contracts cover blocks 11 and 12 in the Pelotas basin and block 6 in the Punta del Este basin and together cover an area of almost 26,000km^2. The PSAs provide that BP will hold a 100% interest in the blocks and the Uruguayan state oil company, ANCAP, will have a right to participate in up to 30% of any discoveries. BP intends to carry out 2D and 3D seismic acquisition on the blocks during the initial three-year exploration phase of the contracts. This work is expected to begin in 2013.

In Trinidad & Tobago, BP almost doubled its exploration and production licences acreage during 2012, and now holds licences covering 1,806,000 acres offshore of the east coast. Facilities include 13 offshore platforms and one onshore processing facility. Production is comprised of oil, gas and NGLs. In May, BP announced that it had signed two PSAs with the government of Trinidad & Tobago for the two deepwater exploration and production blocks awarded in 2011. BP has a 100% interest in both these blocks.

Africa

BP's upstream activities in Africa are located in Angola, Algeria, Libya, Egypt and Namibia.

BP is present in nine major deepwater licences offshore Angola and is operator in four of these. In addition, BP holds a 13.6% interest in the Angola LNG project.

- The Clochas and Mavacola fields (BP 26.7%), operated by Esso Angola, started production in May 2012 and are steadily ramping up. Production reached 65,000 barrels of oil per day by the end of 2012.
- In December 2012 production from the PSVM development area in Block 31, offshore Angola, started. Initial production, coming from the Plutão field, averages 60,000 barrels of oil per day. PSVM is expected to build towards plateau rates of 150,000 barrels per day of oil over the coming year.

In 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. In addition, BP is in a joint venture with Sonatrach in the Bourarhet Sud block, located to the south west of In Amenas. The Bourarhet licence has been extended until September 2014 and appraisal is ongoing. BP's total assets in Algeria at 31 December 2012 were $2,372 million ($335 million current and $2,037 million non-current).

- On 16 January 2013, a terrorist attack occurred at the In Amenas joint venture site. Following the incident, BP had a staged reduction of non-essential workers out of Algeria as a precautionary and temporary measure. Limited production from Train 1 restarted on 22 February. We are working with our joint-venture partners to assess the broader impact of the incident. BP remains committed to operating in Algeria where it has high-quality assets.

In Libya, BP is in partnership with the Libyan Investment Authority (LIA) to explore acreage in the onshore Ghadames and offshore Sirt basins, covered under the exploration and production-sharing agreement (EPSA) ratified in December 2007 (BP 85%). BP's total assets in Libya at 31 December 2012 were $452 million ($101 million current and $351 million non-current).

- On 29 May 2012 BP announced that it had lifted force majeure in respect of its Libyan EPSA with the National Oil Corporation (NOC) with effect from 15 May 2012. Force majeure had been in place since 21 February 2011 following the outbreak of civil unrest in Libya. Since lifting force majeure we have completed the rehabilitation and re-staffing of our Tripoli office, and resumed planning and preparation work towards our onshore and offshore exploration drilling programmes.

In Egypt, BP and its partners currently produce 10% of Egypt's oil production and more than 30% of its gas production. BP's total assets in Egypt at 31 December 2012 were $7,818 million, of which $2,982 million were current (see Financial statements – Note 26 on page 224) and $4,836 million were non-current.

- During 2012 Egypt elected President Morsi and executive power was passed from the interim military ruling council to the new government. There has been a significant reduction in Central Bank foreign currency reserves and the political and economic outlook remains uncertain. Our production and operations continue and we are monitoring and working with the government to manage the situation.
- In June 2012 first gas from the Seth development in Egypt was announced. The Seth field is located 60km offshore in the Ras El Bar concession in the east Nile Delta, close to the existing producing Ha'py and Denise fields.
- In August 2012 BP announced the Taurt North and Seth South gas discoveries in the North El Burg offshore concession (BP 50% and operator), in the Nile Delta. These are the fourth and fifth discoveries made by BP in the concession following Satis-1 and Satis-3 Oligocene deep discoveries and Salmon-1 shallow Pleistocene discovery.

In Namibia, BP is a non-operating partner in five deepwater blocks, which are currently in the exploration phase. All five blocks were accessed in 2012.

Asia

In Asia, BP has activities in Western Indonesia, China, Azerbaijan, Oman, Jordan, Abu Dhabi, India and Iraq.

In 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. BP also participates in the Sanga-Sanga CBM PSA (BP 38%), as well as four other CBM PSAs – Tanjung IV and Kapuas I, II and III in the Barito basin of Central Kalimantan. BP holds a 44% interest in the Pertamina-operated Tanjung IV PSA, and a 45% operating interest in each of the Kapuas I, II and III PSAs. After conducting site visits and further evaluation BP has decided to exit the Kapuas I, II and III CBM PSAs and will transfer its working interest to its partner in each PSA, subject to approval.

In China, BP's upstream activities in the country include production from the China National Offshore Oil Corporation (CNOOC) operated Yacheng offshore gas field (BP 34.3%) as well as deepwater exploration in the South China Sea's Block 42/05 (BP 40.82%) and Block 43/11 (BP 40.82%). In December 2012 BP announced the sale of its interest in Yacheng gas field to Kuwait Foreign Petroleum Exploration Company (see Disposals on page 66).

In Azerbaijan, BP is the largest foreign investor and operates two PSAs, Azeri-Chirag-Gunashli (ACG) and Shah Deniz, and also holds other exploration leases. BP is expecting to progress the sanctioned Chirag Oil project by starting up the West Chirag production and drilling platform in late 2013.

- In 2012 further EU and US regulations concerning restrictive measures against Iran were issued. These further measures clarified that they do not apply to Naftiran Intertrade Co. Ltd (NICO), a Shah Deniz project participant, and as such NICO and Shah Deniz continue to operate in full compliance with EU and US law. For further information see Further note on certain activities on page 45.
- In June 2012 the Shah Deniz consortium announced it was considering two export routes for gas sales to Europe. The Nabucco West project was selected as the single pipeline option for the potential export of Shah Deniz Stage 2 gas to Central Europe. The Trans-Adriatic Pipeline (TAP) was selected as the potential route for export of Stage 2 gas to Italy. The Shah Deniz consortium will continue to work with the owners of both pipeline options and potential gas purchasers to agree transit and marketing terms before selecting the final option and concluding the related gas sales agreements ahead of the Shah Deniz final investment decision planned for mid-2013. Development of the South East Europe Pipeline (SEEP) project will cease.
- In September 2012 BP was offered 12% equity in the Trans-Anatolian gas pipeline (TANAP) by SOCAR, which acts as a project operator and its majority shareholder. In late December 2012 BP (together with Total and Statoil) agreed with SOCAR the main principles for its participation in the TANAP project, the key terms for the TANAP GTA for Shah Deniz Stage 2 gas, as well as a framework for technical co-operation on the project. By the end of 2012 significant progress was also achieved in resolving other outstanding commercial issues with SOCAR including the Shah Deniz Stage 2 gas marketing entity and the South Caucasus Pipeline (SCP) expansion.

BP is currently conducting exploration and appraisal programmes in Jordan and Oman.

In Abu Dhabi, we have equity interests of 9.5% and 14.67% in onshore and offshore concessions respectively. The Abu Dhabi onshore concession expires in January 2014 with a consequent production impact of approximately 140mb/d.

In India, BP has a 30% interest in nine oil and gas PSAs operated by Reliance Industries Limited (RIL), a 50% interest in one operated PSA, and is a partner with RIL in a 50:50 joint venture for the sourcing and marketing of gas in India.

- In 2011, BP acquired from RIL a 30% interest in 21 oil and gas PSAs in India operated by RIL. As part of continued evaluation to high grade the portfolio and focus our efforts, 12 of the blocks acquired were relinquished in 2012.
- During 2012 progress continued toward the anticipated ramp-up of drilling and project activity in 2013. Activities to arrest the decline in production on Block KG D6 fields were approved by the relevant authorities and execution planning has commenced. The government also approved the submitted Field Development Plan (FDP) of Satellite I discoveries, declaration of commerciality of R-Series discoveries and appraisal plan of the Cauvery basin block discovery. Site survey and engineering studies have been undertaken to progress already discovered resources in the KG D6 and NEC 25 blocks. The final investment decisions on these projects are subject to completion of appraisal and engineering work, obtaining regulatory approvals and determining gas pricing. Exploration drilling is scheduled to commence in early 2013.

In Iraq, BP holds a 38% working interest and is the lead contractor in the Rumaila technical service contract. Rumaila is one of the world's largest oilfields and was discovered by BP, as part of a consortium, in 1953 and comprises five producing reservoirs.

Australasia

In Australasia, we are active in Australia and Eastern Indonesia.

In Australia, BP is one of seven partners in the North West Shelf (NWS) venture, which has been producing LNG, pipeline gas, condensate, LPG and oil since the 1980s. Six partners (including BP) hold an equal 16.67% interest in the gas infrastructure and an equal 15.78% interest in the gas and condensate reserves, with a seventh partner owning the remaining 5.32%. BP also has a 16.67% interest in some of the NWS oil reserves and related infrastructure. 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[a] in operation. BP also holds a 5.375% interest in the Jansz-lo field and 12.5% interests in the Geryon, Orthrus and Maenad fields which are part of the Greater Gorgon project. In May 2012 the 3D seismic survey of the four deepwater offshore exploration blocks in the Ceduna Sub Basin (BP 100%) awarded in 2011 was completed. The survey covered approximately 12,500km^2. Following interpretation of the seismic survey, BP will drill four deepwater wells in this frontier exploration basin, located within the Great Australian Bight off the coast of southern Australia.

In Eastern Indonesia, BP has a 100% interest in the North Arafura PSA, located on the coast of the Arafura Sea, 480 kilometres south east of our Tangguh LNG plant (BP 37.16% and operator). In addition, BP owns a 32% interest in the Chevron-operated West Papua I and III PSAs, located 120 kilometres to the south of the Tangguh LNG plant (see Liquefied natural gas on pages 70-71). BP also has 100% interests in two deepwater PSAs; West Aru I and II. The PSAs are located 500 kilometres south west of the North Arafura PSA and 200 kilometres west of the Aru island group.

[a] An LNG train is a processing facility used to liquefy and purify natural gas in the formation of LNG.

Midstream activities

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 natural gas liquids (NGLs) extraction business.

Oil and natural gas transportation

BP has direct or indirect interests in certain crude oil and natural gas transportation systems. The following narrative details the significant events that occurred during 2012 by geographical area.

BP's onshore US crude oil and product pipelines and related transportation assets are included in the Downstream segment (see page 77).

Europe

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 80 fields in the central North Sea. The system has a capacity of more than 1 million barrels per day, with average throughput in 2012 of 390mboe/d. During 2012 FPS processed its 8 billionth barrel, having transported and processed more than one third of the total UK North Sea oil produced to date. BP also operates and has a 36% 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 293mboe/d to a natural gas terminal at Teesside in north-east England. Average throughput in 2012 was 54mboe/d. CATS offers natural gas transportation and processing services. In addition, BP operates the Sullom Voe oil and gas terminal in Shetland. The Dimlington and Easington terminals in Humberside form part of the southern gas assets, the sale of which was completed in November 2012 (see Disposals on page 66).

North America

BP owns a 46.9% interest in the Trans-Alaska Pipeline System (TAPS). The TAPS transports crude oil from Prudhoe Bay on the Alaska North Slope to the port of Valdez in south-east Alaska.

- In April 2012 the two minority owners of TAPS, Koch (3.08%) and Unocal (1.37%) gave notice to BP, ExxonMobil (20.4%) and ConocoPhillips (28.2%) of their intentions to withdraw as an owner of TAPS. The effect of these notifications and the resultant ownership interest and abandonment obligations are still under discussion and regulatory review.
- In September 2012 BP, ExxonMobil and ConocoPhillips entered into two settlement agreements among themselves on the pooling of costs on TAPS and the agreements are under review by the Federal Energy Regulatory Commission.

Asia

BP, as operator, holds a 30.1% interest in and manages the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. The 1,768-kilometre pipeline transports oil from the BP-operated ACG oilfield in the Caspian Sea, along with other third-party oil, to the eastern Mediterranean port of Ceyhan and has a capacity of 1.2 million barrels per day. Average throughput in 2012 was 673mboe/d. BP is technical operator of, and holds a 25.5% interest in, the 693-kilometre South Caucasus Pipeline, which takes gas from Azerbaijan through Georgia to the Turkish border and has a capacity of 134mboe/d with average throughput in 2012 of 67.8mboe/d. In addition, BP operates the Western Export Route Pipeline between Azerbaijan and the Black Sea coast of Georgia (as operator of Azerbaijan International Operating Company).

Liquefied natural gas

Our LNG activities are located in Abu Dhabi, Angola, Australia, China, Indonesia and Trinidad. 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.

In Abu Dhabi, we have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2012 supplied 5.6 million tonnes of LNG (289 billion cubic feet equivalent regasified).

In Angola, BP has a 13.6% share in the Angola LNG project, which is expected to receive approximately 1 billion cubic feet of associated gas per day from offshore producing blocks and to produce 5.2 million tonnes per annum of LNG (gross), as well as related gas liquids products. The Angola LNG plant is in the process of being commissioned and is expected to start production in 2013.

In Australia, BP is one of seven partners in the 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 2.7 million tonnes per annum of LNG. BP is also one of five partners in the Browse LNG venture (operated by Woodside) and holds a 17% interest. A proposed greenfield LNG development for Browse hydrocarbons is being considered by the Browse joint venture and is currently in the early design stage. The proposed development remains subject to regulatory, joint-venture and internal BP approvals.

In China, BP has a 30% equity stake in the 7 million tonnes per annum 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 described above.

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 16% of the total gas feed to Bontang, one of the world's largest LNG plants. The Bontang plant has a capacity of 22 million tonnes per annum of LNG and produced more than 11 million tonnes of LNG in 2012. Also in Indonesia, BP has its first operated LNG plant, Tangguh (BP 37.16%), in Papua Barat. The asset comprises 14 producing wells, two offshore platforms, two pipelines and an LNG plant with two production trains with a total capacity of 7.6 million tonnes per annum. Tangguh supplies LNG to customers in China, South Korea, Mexico and Japan through a combination of long-, medium- and short-term contracts.

- In December 2012 BP and partners received government approval for the Tangguh expansion project plan of development for a third LNG train at Tangguh, which would increase capacity by 3.8 million tonnes per annum. The new train is expected to be scheduled for commissioning in late 2018.

In Trinidad, BPs net share of the capacity of Atlantic LNG trains 1, 2, 3 and 4 is 6 million tonnes of LNG per year. 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 entitlement from trains 2 and 3 is marketed via BP's LNG marketing and trading business to a variety of markets including the Dominican Republic, India, Japan, South Korea, Spain, the UK and the US.

Gas marketing and trading activities

Marketing and trading of natural gas, power and NGLs provide routes into liquid markets for BP's produced gas, and generate margins and fees associated with the provision of physical products and derivatives to third parties and income from asset optimization and trading.

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, to support group 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 enhances margins from sources such as the management of price risk on behalf of third-party customers. These markets are large, liquid and volatile. Market conditions have become more challenging over the past few years due to the availability of shale gas in North America and an excess of supply on long-term contracts from producers coupled with recession-led demand reduction in Europe. The business (including support functions) operates primarily from offices in Houston and London and employs around 1,200 people.

In connection with its trading activities, the group uses a range of commodity derivative contracts, 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 that seeks to manage and oversee the financial risks associated with this trading activity, which is described in Note 26 to the Financial statements on page 220. The group's trading activities in natural gas are managed by the integrated supply and trading function.

The range of contracts that the group enters into is described in Certain definitions – commodity trading contracts, on page 98.

Downstream

2012 was a year of sustained safety and operational improvements and significant strategic progress in repositioning Downstream, with further progress in our Whiting refinery modernization project (WRMP) and agreement reached on major divestments in the US.

What we do

Our Downstream segment is the product- and service-led arm of BP, focused on fuels, lubricants and petrochemicals. We have significant operations in Europe, North America and Asia, and we also manufacture and market our products across Australasia, southern Africa and Central and South America. The Downstream segment operates hydrocarbon value chains covering three main businesses: fuels, lubricants and petrochemicals.

Fuels – The fuels business is made up of regionally based integrated fuels value chains (FVCs), which include refineries, a number of fuels marketing businesses, a global aviation fuels marketing business, and global oil supply and trading activities. These businesses sell refined petroleum products including gasoline, diesel, aviation fuel and LPG.

Lubricants – Our lubricants business manufactures and markets lubricants and related products and services. It is a global business adding value through brand, technology and relationships.

Petrochemicals – Our petrochemicals business produces petrochemicals products at manufacturing locations around the world leveraging proprietary BP technology. These products are then used by others to make vital consumer products such as paints, plastic bottles and fibres for clothing.

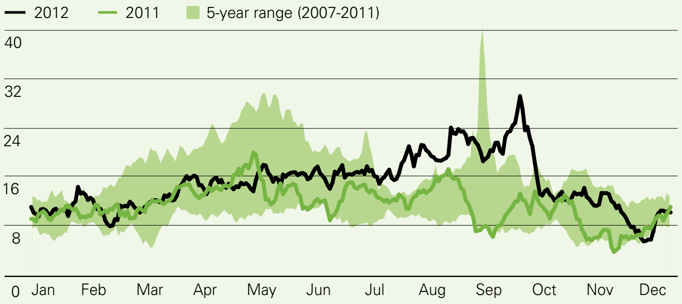
Our strategy

In Downstream we are focused on a consistent set of priorities executed in a systematic and disciplined way.

- These priorities start with safety and include excellent execution, portfolio quality and integration and growing margin share through exposure to growth.
- Our segment strategy is about winning sustainably in the markets in which we choose to participate. This means seeking to outperform the best competitor in a region and doing it safely.
- Our aim is to invest to strengthen our established positions while maintaining overall capital employed. Over time we will seek to shift participation and capital employed from established to growth markets.
- We strive to do this within a stable financial framework delivering attractive returns and growth in earnings and cash flow.

Our market – 2012 summary

Global refining marker margin ($/bbl)

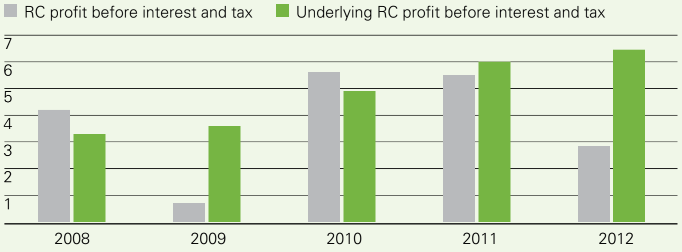


- Globally, average refining margins improved as refinery closures and operational issues reduced product supply.
- Global lubricants demand continued to be weak in 2012 as a result of economic slowdown, despite growth in excess of 2% in the emerging markets of Brazil, Russia, India and China.
- Petrochemicals margins for our products suffered steep declines driven by capacity additions in Asia, coupled with lower growth in demand.

Our performance – 2012 summary

- The process safety metrics of loss of primary containment and process safety incident index improved compared with 2010 and 2011 (see pages 73-74).
- In 2012 replacement cost profit before interest and tax for the segment was $2.8 billion, compared with $5.5 billion in 2011. After adjusting for non-operating items and fair value accounting effects, we delivered a record underlying replacement cost profit[a] before interest and tax of $6.4 billion, compared with $6.0 billion in 2011, despite a significant reduction in the supply and trading contribution (see page 74).
- We announced that we have agreed to sell our Carson refinery in California and associated marketing and logistics to Tesoro Corporation for an estimated $2.5 billion, and our Texas City refinery and associated assets to Marathon Petroleum Corporation for up to $2.4 billion. The sale of Texas City was completed on 1 February 2013. During the year we recognized impairment losses totalling $2.6 billion related to these assets held for sale.
- We have made significant progress on WRMP, which remains on track to be commissioned in the second half of 2013 (see page 76).
- As part of our exit from the LPG bulk and bottled business we announced sales of six of the nine country operations to be sold and completed three of these sales during 2012.
- In 2012 the lubricants business once again delivered more than $1 billion of profit on both a replacement cost and underlying replacement cost basis. This is the fifth consecutive year in which the lubricants business has delivered more than $1 billion of underlying replacement cost profit.
- In petrochemicals, we completed the first steps in implementing a new licensing strategy. We signed licences with two third parties for use of our proprietary technology in world-scale plants in India.
- We also made further progress on major petrochemicals projects in India and China (see pages 78-79).

Downstream profitability ($ billion)



Outlook

- In 2013 we expect refining margins to decline slightly from the relatively high average levels seen in 2012 as further refining capacity comes onstream and demand continues to be weak in many markets.
- We expect the financial impact of refinery turnarounds in 2013 to be lower than in 2012.
- Demand for lubricants in 2013 is expected to be similar to 2012.
- We expect the petrochemicals market to remain difficult in 2013 as further new Chinese PTA capacity enters the market.
- We expect our segment capital expenditure to be slightly lower in 2013 than in 2012 as we enter the final phase of WRMP.

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[a] Underlying replacement cost profit before interest and tax is not a recognized GAAP measure. See footnote b on page 34 for further information. The equivalent measure on an IFRS basis is replacement cost profit before interest and tax.

With effect from 1 January 2012, we reported the Refining and Marketing segment as Downstream, with no changes in the composition of the segment.

Market commentary

The weakness in the global economy continued in 2012 (see page 12), creating a challenging demand environment for our downstream businesses.

In 2012 we saw a significant improvement in refining margins, which were, on average, over $3 per barrel higher than in 2011, driven mainly by supply-side issues experienced by the industry throughout 2012.

We track the margin environment by way of a global refining marker margin. Refining margins are a measure of the difference between the price a refinery pays for its inputs (crude oil) and the market price of its products. Although refineries produce a variety of petroleum products, we track the margin environment by way of a simplified indicator that reflects the margins achieved on gasoline and diesel only. The refining marker margin (RMM) is calculated at a regional level using region-specific marker crudes and product grades that are then weighted by our refining capacity in the region to an aggregate BP average RMM. The RMM may not be representative of the margin achieved by BP in any period because of BP's particular refinery configurations and crude and product slates. Many of our competitors adopt a similar approach as it enables simplified benchmarking on a like-for-like basis. The RMM does not include estimates of fuel costs or other variable costs.

				$ per barrel
	Crude marker	**2012**	2011	2010
Refining marker margin (RMM)				
US West Coast	Alaska North Slope (ANS)	**17.4**	13.6	13.1
US Gulf Coast	Mars	**16.1**	11.9	10.2
US Midwest	Light Louisiana Sweet (LLS)	**10.3**	7.5	6.0
Northwest Europe	Brent	**16.1**	11.9	10.4
Mediterranean	Azeri Light	**12.7**	9.0	8.8
Singapore	Dubai/Tapis blend	**15.3**	14.6	10.7
BP average RMM		**15.0**	11.6	10.0

The RMMs for 2012 were higher than 2011 in all the regions that we operate in. The global BP RMM averaged $15.0/bbl compared with the 2011 RMM of $11.6/bbl. Higher margins were mainly attributable to the refining capacity gap left by refinery closures on the US east coast and in Europe, removing nearly 1.8 million barrels per day of refined products from the market at the peak of the closures. Refining margins tend to follow a seasonal pattern in which they usually peak in the second quarter and then decline through the rest of the year. In 2012, however, the peak occurred in the third quarter as a result of unplanned refinery unit outages and closures combined with hurricane activity in the US Gulf Coast and low product inventories. Industry-wide utilization rates were around the same level as 2011, but significantly lower than the five-year average, mostly driven by the previously mentioned refinery closures.

These restrictions on supply were partially offset by lower demand for petroleum products in the OECD. This demand reduction was driven by low economic growth, increased blending of biofuels and increased car fleet efficiencies. In addition there have been changes in consumer behaviour such as a long-term decline in demand for gasoline and growth in diesel demand in Europe. Nonetheless, higher refining margins were available in the year due to growth in non-OECD countries' demand for oil products, which attracted gasoline and diesel exports from the regions in which BP operates.

Our refineries, particularly Toledo and Whiting in the US, benefited from a location advantage as they were able to access discounted crudes. Throughout 2012, US midcontinent crudes priced off the West Texas Intermediate (WTI) marker, remained cheaper than waterborne crudes of a similar quality, such as European Brent and Gulf Coast LLS, due to increased production from shale oil, combined with bottleneck logistical capacity constraints in transporting these crudes to the coast. Heavy Canadian crudes continued to flow into the US as producers ramped up production and consequently these grades of crude were less expensive than last year when compared with lighter crudes.

Globally, the impact of Libyan sweet crude returning to the market after the end of the civil war of 2011 was compounded by the advances in shale oil production in the US, which reduced the demand-pull of these crude types from abroad. This made sweet crudes globally less expensive compared with previous years. OPEC production was also higher than 2011 and reached around 31.5 million barrels per day, on average. This helped to offset the loss of Iranian oil following an embargo by the US and Europe and markets generally remained well supplied throughout the year. Upward pressure on prices, mainly attributable to geopolitical issues such as unrest in the Middle East (particularly Iran and Syria) and concerns over the stability of the eurozone were generally offset by a tepid global economic outlook.

In February 2013 BP updated the RMM methodology and regions to reflect the changes to our US portfolio after the refinery divestments and trends in regional crude markets since the RMM was established. For example, a new Australia region, using Brent crude, replaced the Singapore RMM, which was based previously on a Dubai/Tapis crude blend. This change has been made to better reflect the types of crude that Australian refiners process. In addition, we changed the marker crude for the US Midwest region from Gulf Coast LLS to WTI to reflect the increased availability of the lower-cost crudes in the US midcontinent mentioned previously.

The effect of this update is that the 2012 BP average RMM will be restated in the *BP Annual Report and Form 20-F 2013* from $15.0 per barrel (as reported here) to $18.2 per barrel.

The global lubricants market continued to be challenging in 2012 as a result of economic slowdown and low demand growth. The automotive sector has been squeezed by pressure on real incomes, which has resulted in demand for new passenger vehicles in the EU falling 8.2% in 2012. Industrial demand has also been under pressure from weak manufacturing production. Lubricants base oil prices were, however, lower than in 2011, which helped alleviate some of the downward pressure on margins.

Compared with 2011, there was a sharply deteriorating business environment for the focused group of petrochemicals products that BP produces. Substantial capacity additions in Asia in combination with global demand slowdown meant a deterioration of both purified terephthalic acid (PTA) and paraxylene (PX) margins with PTA margins at very low levels. The petrochemicals margin environment has tended to be cyclical in the past, with times of high margins during periods of demand increases and economic growth leading to investment in new capacity to meet this demand, followed by periods of lower margins as this new capacity comes onstream. 2012 has represented a downward cycle and although by the end of 2012 there were some signs of recovery, we expect the market to remain difficult in 2013 as further Chinese capacity additions enter the market.

By contrast, competitors who have significant production of ethylene, olefins, and derivatives in the US have seen advantage through the low cost of natural gas. This has resulted in many ethylene crackers being converted from 'heavy' feeds (liquids priced with crude oil) to 'light' feeds (gas, priced against US natural gas) resulting in strong margins for these players.

2012 performance

Safety performance

Safe, reliable and compliant operations remain the top priority within Downstream. This is underpinned by the systematic implementation of BP's operating management system (OMS) by all entities. (See Safety on pages 46-50 for further information on safety and OMS.)

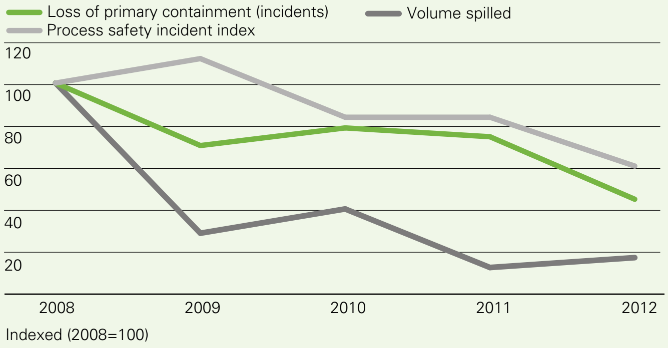
In 2012 the Downstream segment continued the journey to enhance local systems and processes at our sites in response to OMS. For example, in 2012, a programme designed to improve the capability of the workforce to identify and mitigate risks within their local OMS was rolled out. This brings specialist coaches and entity teams together to improve safety and performance by systematically closing gaps between local work processes and OMS standards and then embeds these improvements through front-line engagement and training. We have also focused on improving the capability to reduce risk through OMS through the 'learning from incidents' process. Drawn from incident investigations and the risk process, targeted 'high-value learning' and 'learning alert' communications show front-line teams what went wrong or could go wrong, and the actions to take to prevent similar incidents from happening at their site.

Safety performance is monitored by a suite of input and output metrics, which focus on personal and process safety. Regrettably, there were two workforce fatalities in 2012. In India, a contractor fell through a roof sheet while installing a fall prevention line and, in Scotland, a contractor vehicle collided with a third-party vehicle resulting in fatal injuries to the contract driver. These tragic events have been fully investigated.

Two of the key measures used to track process safety are the process safety incident index (PSII), a weighted index that reflects both the number and severity of events per 200,000 hours worked and loss of primary containment (LOPC), a measure of unplanned or uncontrolled releases of material from primary containment. The PSII has improved by 40% since it was established in 2008. In 2012 it was 0.26 compared with 0.36 in 2011. There was also a 40% reduction in the number of LOPC, from 2011 to 2012, falling from 195 in 2011 to 117 in 2012. In addition, the number of oil spills greater than one barrel reduced from 145 in 2011 to 96, however the volume of these spills for 2012 was higher at 0.6 million litres compared with 0.4 million litres in 2011.

Key process safety metrics 2008-2012

(number of incidents)



We measure our personal safety performance through recordable injury frequency (RIF) and days away from work case frequency (DAFWCF) as well as the severe vehicle accident rate (SVAR). In 2012 our RIF (measured by the number of recordable injuries to the BP workforce per 200,000 hours worked) was 0.33, better than the 2011 rate of 0.37. The 2012 DAFWCF, a subset of the RIF that measures the number of cases where an employee misses one or more days from work per 200,000 hours worked) was 0.09, compared with 0.11 in 2011.

Driving safety has continued to be an area of focus in 2012 with the formation of a driving safety team to facilitate how we manage the risks associated with driving in an effective and consistent manner. Despite this, the severe vehicle accident rate[a] increased in 2012 to a rate of 0.16 compared with 0.11 in 2011.

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[a] The severe vehicle accident rate (SVAR) is the number of vehicle incidents that result in death, injury, a spill, a vehicle rollover, or serious or disabling vehicle damage per one million kilometres travelled.

Financial and operating performance

			$ million
	2012	2011	2010
Replacement cost profit before interest and tax[a]			
Fuels	**1,385**	3,003	2,628
Lubricants	**1,276**	1,350	1,357
Petrochemicals	**185**	1,121	1,570
	2,846	5,474	5,555
Net (favourable) unfavourable impact of non-operating items and fair value accounting effects[b]			
Fuels	**3,611**	640	(381)
Lubricants	**9**	(100)	47
Petrochemicals	**(19)**	(1)	(338)
	3,601	539	(672)
Underlying replacement cost profit before interest and tax[ac]			
Fuels	**4,996**	3,643	2,247
Lubricants	**1,285**	1,250	1,404
Petrochemicals	**166**	1,120	1,232
	6,447	6,013	4,883
Sales and other operating revenues[d]	**346,491**	344,116	266,751
Capital expenditure and acquisitions	**5,048**	4,130	4,029
			thousand barrels per day
Total refinery throughputs[e]	**2,354**	2,352	2,426
			%
Refining availability[f]	**94.8**	94.8	95.0
			thousand tonnes
Total petrochemicals production[g]	**14,727**	14,866	15,594

[a] Income from petrochemicals produced at our Gelsenkirchen and Mülheim sites is reported within the fuels business. Segment-level overhead expenses are included within the fuels business.

[b] Fair value accounting effects represent the (favourable) unfavourable impact relative to management's measure of performance (see page 37 for further details). For Downstream, these arise solely in the fuels business.

[c] Underlying replacement cost profit is not a recognized GAAP measure. See footnote b on page 34 for information on underlying replacement cost profit.

[d] Includes sales between businesses.

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

[f] 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.

[g] Petrochemicals production includes 1,625kte of petrochemicals produced at our Gelsenkirchen and Mülheim sites in Germany for which the income is reported in our fuels business.

Replacement cost profit before interest and tax for the year ended 31 December 2012 was $2,846 million, compared with $5,474 million for the previous year. The full-year results included a net loss for non-operating items of $3,174 million, compared with a net loss of $602 million in 2011. The non-operating items in 2012 mainly related to impairments. (See page 37 for further information on non-operating items.) In addition, fair value accounting effects had an unfavourable impact of $427 million, compared with a favourable impact of $63 million in 2011. (See page 37 for further information on fair value accounting effects.)

After adjusting for non-operating items and fair value accounting effects, Downstream reported record underlying replacement cost profit before interest and tax in 2012 of $6,447 million.

The fuels business delivered an underlying replacement cost profit before interest and tax of $4,996 million for the year; compared with $3,643 million in 2011. This reflects strong operations that enabled us to capture the favourable refining environment, partly offset by a reduction in the supply and trading contribution for the year compared with 2011. The following table summarizes the volume, by region, of crude oil and feedstock processed by BP for its own account and for third parties. Utilization data is also summarized.

			thousand barrels per day
Refinery throughputs[a]	**2012**	2011	2010
US	**1,310**	1,277	1,350
Europe	**751**	771	775
Rest of World	**293**	304	301
Total	**2,354**	2,352	2,426
Refinery capacity utilization			
Crude distillation capacity at 31 December[b]	**2,681**	2,679	2,667
Refinery utilization[c]	**88%**	88%	91%
US	**89%**	87%	93%
Europe	**89%**	91%	91%
Rest of World	**80%**	84%	84%

[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 throughput (thousands of barrels/day) divided by crude distillation capacity, expressed as a percentage.

Overall refinery throughputs were at a similar level to 2011, notwithstanding the planned outage of the largest of the crude units at our Whiting refinery in the fourth quarter.

The lubricants business delivered an underlying replacement cost profit before interest and tax of $1,285 million for the year, compared with $1,250 million in 2011, reflecting continued robust performance despite challenging levels of demand. This is the fifth consecutive year in which the lubricants business has delivered more than $1 billion of underlying replacement cost profit.

The petrochemical business delivered an underlying replacement cost profit before interest and tax of $166 million for the year, compared with $1,120 million in 2011, reflecting weakness in margins for BP's mix of products compared with last year resulting from recent capacity additions in Asia and lower demand growth than in 2011. Our petrochemicals production was lower than 2011 at 14,727 thousand tonnes compared with 14,866 in 2011 as a result of decisions to reduce production for commercial reasons.

2012 was the highest ever underlying replacement cost profit delivery in the Downstream segment reflecting the fourth consecutive year of underlying replacement cost profit growth. In March 2010 we outlined an opportunity to deliver an additional $2 billion of performance improvement by 2012 relative to a 2009 base-line.[a] However, despite better operational reliability and high utilization rates that allowed us to capture more of the available margin, and improvements in our cost efficiency, we were unable to fully deliver this level of improvement principally due to a significant reduction in the supply and trading contribution in 2012 compared with a particularly strong performance in 2009.

[a] This performance improvement measure was based on comparing Downstream's underlying replacement cost profit before interest and tax for 2009 with that of 2012, after adjusting for the impact of changes in the refining margin and petrochemicals environment (including energy costs), foreign exchange impacts and price-lag effects for crude and product purchases. This adjusted measure of underlying replacement cost profit before interest and tax is non-GAAP. We believe the measure is useful to investors because it is one that is viewed and tracked by management as an important indicator of segment performance.

Sales and other operating revenues in 2012 were $346 billion, a similar level to the $344 billion in 2011, and higher than the $267 billion in 2010. This increase reflects higher prices almost offset by lower volumes and foreign exchange losses.

			$ million
	2012	2011	2010
Sale of crude oil through spot and term contracts	**56,383**	57,055	44,290
Marketing, spot and term sales of refined products	**275,920**	273,940	209,221
Other sales and operating revenues	**14,188**	13,121	13,240
Sales and other operating revenues[a]	**346,491**	344,116	266,751

[a] Includes sales between businesses.

The following table sets out oil sales volumes by type for the past three years. Marketing sales volumes were 3,213mb/d, slightly lower than 2011, principally reflecting reduced demand in some OECD markets and simplification of our portfolio.

			thousand barrels per day
Refined product volumes	**2012**	2011	2010
Marketing sales[a]	**3,213**	3,311	3,445
Trading/supply sales[b]	**2,444**	2,465	2,482
Total refined product sales	**5,657**	5,776	5,927
Crude oil[c]	**1,518**	1,532	1,658
Total oil sales	**7,175**	7,308	7,585

[a] Marketing sales include 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.

[c] Crude oil sales relate to transactions executed by our integrated supply and trading function, primarily for optimizing crude oil supplies to our refineries and in other trading. Seventy-three thousand barrels per day relate to revenues reported by Upstream.

Prior years' comparative financial information

Replacement cost profit before interest and tax for the year ended 31 December 2011 was $5,474 million, compared with $5,555 million for the previous year. The 2011 results included a net loss for non-operating items of $602 million, compared with a net gain of $630 million in 2010. The non-operating items in 2011 mainly related to impairment charges relating to our disposal programme, partially offset by gains on disposal (see page 37 for further information on non-operating items). In addition, fair value accounting effects had a favourable impact of $63 million, compared with a favourable impact of $42 million in 2010 (see page 37 for further information on fair value accounting effects).

In the fuels business, we were able to capture the benefits available in 2011 from BP's location advantage in accessing WTI-based crude grades. Compared with 2010, the result also benefited from a higher refining margin environment and a stronger supply and trading contribution. These benefits were partly offset by a significantly higher level of turnarounds in 2011 than 2010 and negative impacts from increased relative sweet crude prices in Europe and Australia and the weather-related power outages in the second quarter.

Performance in our lubricants business in 2011 was impacted by significant base oil price increases and weaker demand. These impacts were partly offset by supply-chain efficiencies and our ability to recover the increased cost of goods in the market.

In our petrochemicals business, compared with 2010, the 2011 result was negatively impacted by weakening market conditions as the year progressed as additional Asian capacity came onstream during the year at a time of weaker demand. This was somewhat offset by the strength in aromatics margins and volumes in the first half of the year.

The replacement cost profit before interest and tax for the year ended 31 December 2010 of $5,555 million included a net gain for non-operating items of $630 million, mainly relating to gains on disposal, partly offset by restructuring charges. In addition, fair value accounting effects had a favourable impact of $42 million relative to management's measure of performance. The primary additional factors contributing to the increase in replacement cost profit before interest and tax compared with 2009 were improved operational performance in the fuels value chains (FVCs), continued strong operational performance in lubricants and petrochemicals, and further cost efficiencies, as well as a more favourable refining environment. Against very good operational delivery, the results were impacted by a significantly lower contribution from supply and trading compared with 2009.

Our businesses

Fuels

The fuels businesses is made up of seven regionally based FVCs, a number of regionally focused fuels marketing businesses, a global aviation fuels marketing business and our global oil supply and trading activities. These fuels businesses sell refined petroleum products including gasoline, diesel, aviation fuel and LPG.

Fuels value chains

The FVCs seek to optimize the activities of our assets across the supply chain: crude delivery to the refineries; manufacture of high-quality fuels;

distribution through pipeline and terminal infrastructure; and marketing and sales to our customers on a regional basis. This integration, together with a focus on excellent execution and cost management as well as a strong brand, market presence and customer base, are key to our financial performance.

The FVC strategy focuses on large-scale, feedstock-advantaged, highly upgraded, dual-fuel-capable, well-located refineries integrated into advantaged logistics and marketing. Consequently, in the US, we are in the process of completing refinery sales that will roughly halve our US refining capacity through the sale of our Texas City refinery (which completed on 1 February 2013) and our Carson refinery and related marketing and logistics assets (see refinery table below). The Texas City refinery[a] was not strongly integrated into BP's marketing assets and has limited access to logistics and tankage flexibility. The Carson refinery is gasoline biased and would need investment in logistics and/or configuration to upgrade capability. This portfolio re-shaping will shift the balance of our US refining portfolio to northern tier refineries able to access advantaged, US mid-continent and Canadian crudes and utilize a significantly greater proportion of heavy crudes.

In our remaining FVCs, we believe we have a portfolio of well-located refineries, integrated with strong marketing positions offering the potential for improvement and growth.

[a] We will retain the petrochemicals manufacturing plants at Texas City.

Refining

At 31 December 2012, we owned or had a share in 16 refineries producing refined petroleum products that we supply to retail and commercial customers. On 1 February 2013 we completed the sale of the Texas City refinery and a portion of our retail and logistics network in the south-east US to Marathon Petroleum Corporation for up to $2.4 billion. In addition, we have announced the sale of our South West FVC including the Carson refinery in California, *ARCO* network and related logistics assets in the region to Tesoro Corporation for $2.5 billion and we expect to close this sale by the middle of 2013 subject to regulatory and other approvals.

Strategic investments in our refineries are focused on securing the safety and reliability of our assets while improving the relative unit margins to capture capability versus the competition. The most important of these strategic investments under way is the Whiting refinery modernization project (WRMP), which we expect will allow the capture of additional margin through the processing of a greater proportion of heavy crudes.

This project made significant progress in 2012 as we entered the heaviest field construction phase. The new crude oil unit, coker, upgraded sulphur recovery complex and gasoil hydrotreater all advanced towards their targeted start-up dates in 2013. The largest of the refinery's crude units, which processed sweet crude, was taken out of service in early November. This outage will allow construction of a replacement crude distillation unit, and will facilitate demolition of the existing unit, thereby enabling the expected start-up of the WRMP project in the second half of 2013. BP is temporarily redeploying refining and technical resources from around the world to assist with the start-up of the new units.

We continue to invest in developing capability to produce cleaner fuels to meet the requirements of our customers and their communities. For example, we are currently investing in a new hydrotreater unit and hydrogen plant at our Cherry Point refinery. This project is designed to allow the refinery to produce fuels that meet ultra-low sulphur diesel (ULSD) standards for rail and marine diesel customers. In addition, the new hydrogen plant is designed to improve operation of naphtha reforming units at the refinery. The project has progressed steadily

The following tables summarize the BP group's interests in refineries and average daily crude distillation capacities as at 31 December 2012.

					thousand barrels per day
				Crude distillation capacities[a]	
	Refinery	Fuels value chain	Group interest[b] %	Total	BP share
US					
California	Carson[c]	US South West	100.0	266	266
Washington	Cherry Point	US North West	100.0	234	234
Indiana	Whiting	US East of Rockies	100.0	413	413
Ohio	Toledo	US East of Rockies	50.0	160	80
Texas	Texas City[c]	–	100.0	475	475
Total US				1,548	1,468
Europe					
Germany	Bayernoil[d]	Rhine	22.5	217	49
	Gelsenkirchen	Rhine	50.0	265	132
	Karlsruhe[d]	Rhine	12.0	322	39
	Lingen	Rhine	100.0	95	95
	Schwedt[d]	Rhine	18.8	239	45
Netherlands	Rotterdam	Rhine	100.0	377	377
Spain	Castellón	Iberia	100.0	110	110
Total Europe				1,625	847
Rest of World					
Australia	Bulwer	Australia New Zealand	100.0	102	102
	Kwinana	Australia New Zealand	100.0	146	146
New Zealand	Whangarei[d]	Australia New Zealand	23.7	118	28
South Africa	Durban[d]	Southern Africa	50.0	180	90
Total Rest of World				546	366
Total				3,719	2,681
Capacity relating to assets held for sale					(741)
Total capacity post-divestment					1,940

[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] Refinery classified as assets held for sale at 31 December 2012.
[d] Indicates refineries not operated by BP.

through 2012 and we expect to complete construction and commissioning by the middle of 2013.

In addition, we completed construction and started up a new, higher efficiency naphtha reformer at our joint venture Toledo refinery in March 2013.

In addition to refined petroleum products, we also blend and market biofuels in our FVCs. In 2012 we blended over 7 billion litres of biofuels into finished product in our FVCs, mainly in Europe and the US. Biogasoline (bioethanol) and biodiesel (hydrogenated vegetable oils and fatty acid methyl esters) continue to grow in volume, primarily in Europe and the US, as regulatory requirements demand heavier blending levels. Our response is to continue to develop blend capabilities and to work with regulators, biofuels supply chains and other stakeholders to improve the sustainability of the biofuels we blend and supply.

Developing new refining technology is also an important part of our strategy. Our refining and logistics technology team is focused on optimizing crude oil selection, utilization and refinery processing capability. They develop and deploy technology and apply knowledge and expertise to support BP's refining and logistics assets. They drive excellence in operational and commercial performance (see Technology pages 57-59).

The London 2012 Olympic and Paralympic Games showcased BP's expertise and technology leadership in biofuels through the development of three advanced biofuel formulations (lignocellulosic ethanol, diesel from sugar and biobutanol from sugar). These new formulations blended with *BP Ultimate*, fuelled the London 2012 Olympic fleet. We continue to work proactively with governments and regulatory bodies in all the countries in which we operate to develop practical and effective solutions to meet local and regional biofuel mandates.

Logistics and marketing

Downstream of our refineries, we operate an advantaged infrastructure and logistics network (which includes pipelines, storage terminals and road or rail tankers), and seek to drive excellence in operational and transactional processes, and deliver compelling customer offers in the various markets in which we operate.

We supply fuel and related convenience services to retail consumers through company-owned and franchised retail sites, as well as other channels, including wholesalers and jobbers. We supply commercial customers within the transport and industrial sectors. We also focus on creating sustainable, differentiated high performance, energy efficient, cleaner and competitive fuels through our fuels technology group. We continue to support our partners and customers in delivering greater energy efficiency and reduced CO_2 emissions in both established and emerging markets and we are working on new fuels that deliver improved fuel economy and compatibility with the latest engine technology and with biofuel components.

Our retail network is largely concentrated in Europe and the US, but also has established operations in Australasia and southern Africa. We have developed networks in China in two separate joint ventures, one with PetroChina and the other with China Petroleum and Chemical Corporation (Sinopec). These two joint ventures operate over 700 dual-branded sites in China. We have also licensed the *BP* brand for use on retail sites to Hellenic Petroleum, which operates around 1,000 BP-branded retail sites in Greece, and to Delek, which operates around 400 BP-branded retail sites in France.

The following table shows the number of BP-branded retail sites by region. Some of these retail sites include a convenience store, which offers consumers a range of food, drink and other consumables and services in a convenient and innovative manner. The convenience offer includes brands such as *Wild Bean Café* and *Petit Bistro* and includes partnerships with leading retailers such as Marks & Spencer in the UK.

	Number of retail sites operated under a BP brand		
Retail sites[a] [b]	**2012**	2011	2010
US	**10,100**	11,300	11,300
Europe	**8,300**	8,200	8,400
Rest of World	**2,300**	2,300	2,400
Total	**20,700**	21,800	22,100

[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. Retail sites are primarily branded *BP*, *ARCO* and *Aral*.

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

As at 31 December 2012, BP's worldwide retail network consisted of some 20,700 sites across the US, Europe, Australia, New Zealand and southern Africa. This is a reduction of about 1,100 since 2011, primarily due to a reduction in the US where we are focusing on higher throughput sites. These retail sites are primarily branded *BP*, *ARCO* and *Aral*. We expect the number of branded retail sites to fall by around 800 in 2013 in the US south west, as we dispose of the *ARCO* brand as part of the sale of the US South West FVC to Tesoro Corporation. BP intends to license back the *ARCO* brand post divestment for use in the North West FVC. BP will, however, retain ownership of the *ampm* convenience store brand after the disposal and franchise it to Tesoro Corporation for use in the south-west US.

Supply and trading

BP's integrated supply and trading function is 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 oil trading business (including support functions) has trading offices in Europe, the US and Asia and employs around 1,800 people. This enables the function to maintain a presence in the more actively traded regions of the global oil markets in order to gain an overall understanding of the supply and demand forces across this market. It has a two-fold strategic purpose in our business.

First, it 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 and purchase alternative crudes from third parties for its refineries where this will provide incremental margin.

Second, the function seeks to create and capture incremental trading opportunities. It enters into the full range of exchange-traded commodity derivatives, over-the-counter (OTC) contracts and spot and term contracts (described in Certain definitions – commodity trading contracts on page 98). In order to facilitate the generation of trading margin from arbitrage, blending and storage opportunities, it also owns and contracts for storage and transport capacity. The group has developed a risk governance framework which seeks to manage and oversee the financial risks associated with this trading activity, see Financial statements – Note 26 on page 220.

The group's trading activities in oil are managed by the integrated supply and trading function. In order to carry out the unique delegations from the BP group, the integrated supply and trading function operates and enforces a robust system of internal control. The internal control systems operated by the regional business leads are augmented by internal support functions that provide independent oversight, including product control, risk, trade completion, and accounting and reporting. They are further supported by regional and group ethics and compliance and group internal audit.

Aviation

Our global aviation business, Air BP, is one of the world's largest and best-known aviation fuels suppliers, serving many major commercial airlines as well as the general aviation and military sectors. We have marketing sales in excess of 460,000 barrels per day. 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. In line with this strategy, in the second quarter of 2012, we completed the acquisition of Shell and Cosan Industria e Commercio's interests in significant aviation fuels assets at seven Brazilian airports, which is an important growth market.

LPG

We are in the process of exiting our global LPG marketing business, which sells bulk and bottled LPG products, in order to simplify our marketing operations. We will retain focus on LPG where it is deeply integrated into our wholesale and autogas sectors in order to optimize refinery and retail operations. As at 31 December 2012, the sales of the LPG business in three countries out of nine had been completed and a further three announced and the integration of the wholesale and autogas sectors into the FVCs is complete.

Lubricants

Our lubricants business manufactures and markets lubricants and related products and services to the automotive, industrial, marine, aviation and energy markets across the world. Distinctive brands, cutting-edge technology and sustaining customer relationships are the cornerstone of our approach. Our key brands are *Castrol*, *BP* and *Aral*. *Castrol* is a recognized brand worldwide and we believe it provides us with a significant competitive advantage. In technology, we apply our expertise to create quality lubricants and high performance fluids for customers in on-road, off-road, air, sea and industrial applications globally.

We divide our lubricants business up into five customer sectors: automotive, marine, industrial, aviation and energy:

- The automotive sector, which accounts for more than two-thirds of our lubricants sales, serves the needs of land-based vehicles including cars, trucks, motorcycles, buses, tractors, earth movers and other vehicles. 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.
- The marine sector serves users of river and sea-going vessels. BP's marine lubricants business is one of the largest global suppliers of lubricants to the marine industry, with a global presence in over 800 ports.
- Our industrial sector serves customers who run or maintain plant and equipment and it is a leading supplier to those sectors of the market involved in the manufacturing of automobiles, trucks, machinery components and steel.
- Our aviation sector serves aircraft operators and maintenance industries. In the aviation industry, we estimate that we are the lubricants supplier for around 40% of the jet engines of the world's commercial airlines.
- Our energy sector serves the oil and gas and power industries. In the oil and gas industry we supply some of world's largest production and drilling companies.

We look to market and sell our products across the world. We sell products direct to our customers in around 45 countries and use approved local distributors for other geographies. Approximately 40% of our employees are located in non-OECD markets and around 20% are located in China and India alone. We are particularly strong in Europe and key Asia Pacific markets including India. In 2012 approximately 50% of the lubricants business replacement cost profit before interest and tax was generated from non-OECD markets.

We have chosen not to participate at scale in base oil or additives manufacturing. We are, however, one of the largest purchasers of base oil in the market.

We participate in blending in locations where scale and competitive advantage can be sustained, or where customer service or security of supply are of critical importance and otherwise difficult to secure. We have a network of 25 wholly owned and operated blending plants worldwide and joint ownership in five others operated by third parties.

Our participation in the value chain is focused on areas of competitive differentiation and strength. These fall into three main areas: the development of formulations and the application of cutting-edge technology; developing product brands and communicating the benefits that our products provide to our customers; and building and extending our relationships with customers so that our products and services are delivered in a manner that best meets their needs.

In lubricants technology we apply our expertise to create quality lubricants and high performance fluids for on-road, off-road, air, sea and industrial applications globally. We continue to support our partners and customers in delivering high-performance lubricants that deliver greater energy efficiency and reduced CO_2 emissions in both established and emerging markets.

During 2012 we launched a Performance Biolubes product line, adding a range of bio-based metalworking fluids and lubricants for use in cutting, grinding, forming and maintenance lubrication. This new technology underpins the *Castrol* brand's commitment to developing environmentally responsible product offers. In addition, we introduced '80BN' (the BN refers to the base number), a new product for the marine market that uses advanced technology to optimize the performance of lubricants in slow-steaming marine engines and further strengthens our credentials in technology leadership. In 2012 we also introduced a co-branded product with Ford to support their new range of environmentally friendly engines.

Our focus is on developing premium products, and we often work alongside original equipment manufacturers in doing this. The new *Castrol EDGE* professional range was launched to the franchised workshop market in Europe and Africa in 2012.

Our lubricants businesses continued to grow the proportion of total sales resulting from premium product sales; in 2012 the percentage of premium sales was 39% compared with 37% in 2011 and 34% in 2010.

Petrochemicals

Our global petrochemicals business has operations in the US, Europe and Asia. The business buys a range of feedstocks for input into our manufacturing units, the majority of which have been built and operate utilizing our proprietary technology. We manufacture and market four main product lines:

- Purified terephthalic acid (PTA).
- Paraxylene (PX).
- Acetic acid.
- Olefins and derivatives (O&D).

We also produce a number of other speciality petrochemicals products.

Our strategy is to leverage our industry-leading technology in the markets in which we choose to participate, to grow the business and to deliver industry-leading returns. New investments are targeted principally in the higher-growth Asian markets. We both own and operate assets, and have also invested in a number of joint ventures in Asia, where our partners are leading companies within their domestic market.

PTA is a raw material used in the manufacture of polyesters used in fibres, textiles and film, and polyethylene terephthalate (PET) bottles. PTA production requires PX as a feedstock, which we produce in the US and Europe and buy in Asia. PTA is then reacted with glycol to produce polyester chips or fibres, which are in turn used to produce PET bottles, polyester fibres and various speciality products, including protective screens for computers and TVs. PX production is primarily from the mixed xylene stream produced in a reformer within a refinery.

Acetic acid is a versatile intermediate chemical used in a variety of products such as paints, adhesives and solvents, as well as in the production of PTA. In producing acetic acid, we purchase methanol and either make or buy carbon monoxide (CO). CO can be produced from a variety of hydrocarbon feedstocks, including natural gas, naphtha, fuel oil and coal.

Our O&D business is based in China and is focused on serving the Chinese market. The SECCO joint venture is between BP, Sinopec and its subsidiary, Shanghai Petrochemical Company. BP also co-owns one other naphtha cracker site outside Asia, which is integrated with our Gelsenkirchen refinery in Germany and this has an associated solvents plant at Mülheim, Germany.

At 31 December 2012, the petrochemicals business ran 15 manufacturing sites including our joint ventures (as shown in the following table), and we have two petrochemicals plants (Gelsenkirchen and Mülheim), which are managed by the fuels business as they utilize feedstock from our

Gelsenkirchen refinery. In October 2012 we sold our interest in BP Chemicals (Malaysia) Sdn Bhd (BPCM), which manufactures PTA with a production capacity of 610,000 tonnes per annum, to Reliance Global Holdings Pte. Ltd. for $230 million.

Our portfolio is underpinned with proprietary technology and leading cost positions allowing BP assets to remain competitive against the newest world-scale units being built in China. These capacity additions and technology advances have resulted in a sharp fall in margins resulting in losses for the older, less efficient producers.

Our technology team develops, deploys and optimizes advantaged chemicals technology to advance the competitiveness of the installed asset base and deliver competitively advantaged projects to access growth. We plan to continue to deploy our advantaged technology in new asset platforms to access the demand centres of Asia and advantaged feedstock sources.

In 2012 we progressed our 1.25-million tonnes per annum PTA project in Zhuhai, China. Below ground preparation work is now complete. We also furthered our growth strategy in Asia by signing a memorandum of understanding with SK Global Chemical Co., Ltd (SKGC) and Sinopec Sichuan Vinylon Works (SVW), to explore the development of an integrated 1,4-butanediol (BDO) and acetic acid project in Chongqing. The proposed 200,000-tonnes per annum BDO plant will be built by SKGC and SVW while the 600,000-tonnes per annum acetic acid plant will be built by our existing acetic acid joint venture in Chongqing. The units in the integrated project are planned to be inter-dependent: the BDO plant will supply acetylene off-gas to the acetic acid plant, which, in return, will supply hydrogen to the BDO plant. This integrated approach is expected to enhance the competitiveness of the complex.

We continue to make progress on our joint study with IndianOil Corp (IOC) to invest in a 1-million tonnes per annum acetic acid plant in Gujarat, India, and have recently completed a refinery integration study to optimize the integration benefits of the proposed project with IOC's refinery.

In 2012, we created a new revenue stream in petrochemicals through third-party licensing of our proprietary PX and PTA technology with two licences being sold in 2012 for use in large-scale plants in India. We also secured a 15-year methanol off-take agreement with Lake Charles's Petcoke Gasification project in Louisiana, US, which will place us well to access advantaged feedstock supply to our acetic acid business.

Petrochemicals production capacity[a,b]

Geographical area	Site	Product	Group interest %	BP share of capacity thousand tonnes per annum[c]
US				
	Cooper River	Purified terephthalic acid (PTA)	100.0	1,300
	Decatur[d]	PTA	100.0	1,000
		Paraxylene (PX)	100.0	1,100
	Texas City	Acetic acid	100.0[e]	600[e]
		PX	100.0	1,300
		Metaxylene	100.0	100
				5,400
Europe				
UK	Hull[d]	Acetic acid	100.0	500
		Acetic anhydride	100.0	200
Belgium	Geel	PTA	100.0	1,300
		PX	100.0	700
Germany	Gelsenkirchen[f]	Olefins and derivatives	50.0 to 61.0	1,800[b,g]
	Mülheim[f]	Solvents	50.0	100[b]
				4,600
Rest of World				
China	Caojing	Olefins and derivatives	50.0	3,300[b]
	Chongqing	Acetic acid	51.0	200[b]
		Esters	51.0	100[b]
	Nanjing	Acetic acid	50.0	300[b]
	Zhuhai	PTA	85.0	1,800[h]
Indonesia	Merak	PTA	50.0	300[b]
South Korea	Ulsan	Acetic acid	51.0	300[b]
		Vinyl acetate monomer	34.0	100[b]
Malaysia	Kertih	Acetic acid	70.0	400[b]
Taiwan	Kaohsiung	PTA	61.4	900[b]
	Taichung	PTA	61.4	500[b]
	Mai Liao	Acetic acid	50.0	200[b]
				8,400
Total BP share of capacity at 31 December 2012				18,400

[a] Petrochemicals production capacity is the proven maximum 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, as indicated.

[c] Capacities are shown to the nearest hundred thousand tonnes per annum.

[d] These sites have capacity under 100,000 tonnes per annum for a speciality product (e.g. naphthalene dicarboxylate and ethylidene diacetate).

[e] Group interest is quoted at 100%, reflecting the capacity entitlement, which is marketed by BP. This capacity is not part of the refinery divestment.

[f] Due to the integrated nature of these plants with our Gelsenkirchen refinery, the income and expenditure of these plants is managed and reported through the fuels business.

[g] Group interest varies by product.

[h] BP Zhuhai Chemical Company Ltd is a subsidiary of BP, the capacity of which is shown above at 100%.

TNK-BP

Since 2003, BP has owned 50% of TNK-BP, an integrated oil company. The other 50% is owned by the consortium of Alfa Access Renova (AAR). TNK-BP's major assets are held by OAO TNK-BP Holding. Other assets of TNK-BP include OAO Slavneft, an equity-accounted joint venture with Gazpromneft in Russia, and TNK Overseas Ltd, which holds its major non-Russian interests. TNK-BP employs about 50,000 staff. Globally, TNK-BP is the tenth largest non-fully state-owned oil company as measured by both SEC proved reserves and hydrocarbon production. It has upstream interests in Russia, Brazil, Venezuela and Vietnam, which produced approximately 2 million barrels of oil equivalent per day (gross TNK-BP) in both 2012 and 2011. TNK-BP also has downstream interests in five refineries in Russia and one in Ukraine, with total throughput of approximately 656mb/d in 2012 compared with 711mb/d in 2011. It has over 1,500 branded retail stations in Russia and Ukraine.

From 1 January 2012, BP's investment in TNK-BP has been reported as a separate operating segment, reflecting the way in which the investment has been managed.

Following the announcement of the agreement described below, BP's investment in TNK-BP met the criteria to be classified as an asset held for sale. Consequently, BP ceased accounting for its interest in TNK-BP using the equity method from 22 October 2012. BP will continue to report its share of TNK-BP's production and reserves until the transaction completes.

Definitive agreements with Rosneft

Having agreed heads of terms on 22 October 2012, BP announced on 22 November that it, Rosneft and Rosneftegaz – the Russian state-owned parent company of Rosneft – had signed definitive and binding sale and purchase agreements (SPAs) for the sale of BP's 50% interest in TNK-BP to Rosneft, and for BP's further investment in Rosneft. The transaction will consist of three tranches:

- BP will sell its 50% shareholding in TNK-BP to Rosneft for cash consideration of $25.4 billion (which includes a dividend of $0.7 billion received from TNK-BP in December 2012) and Rosneft shares representing a 3.04% stake in Rosneft (TNK-BP SPA).
- BP will use $4.8 billion of the cash consideration to acquire a further 5.66% stake in Rosneft from the Russian government at a price of $8 per share (representing a premium of 12% to the Rosneft share closing price on the bid date of 18 October 2012).
- BP will use $8.3 billion of the cash consideration to acquire a further 9.8% stake in Rosneft from a Rosneft subsidiary at a price of $8 per share.

The SPAs were signed after the Russian government approved BP's purchase of the 5.66% stake in Rosneft. On completion, the net result of the overall transaction is that BP will receive $12.3 billion in cash (including $0.7 billion of TNK-BP dividends received by BP in December 2012) and will acquire an 18.5% shareholding in Rosneft. Combined with BP's existing 1.25% shareholding, this will result in BP owning 19.75% of Rosneft. It is expected that the TNK-BP sale and the further investment in Rosneft will complete on the same day. At this level of ownership, BP expects to be able to account for its share of Rosneft's earnings, production and reserves on an equity basis. In due course BP expects to have two seats on Rosneft's nine-person main board.

Completion is subject to certain customary closing conditions, including governmental, regulatory and anti-trust approvals, and is anticipated to occur during the first half of 2013. Under the terms of the SPAs, BP has agreed not to dispose of any of the Rosneft shares acquired in the transaction for at least 360 days following completion. In addition, the TNK-BP SPA contains remedial provisions that take effect if certain events occur.

Financial and operating performance

			$ million
	2012	2011	2010
Profit before interest and tax[a]	**3,370**	4,185	2,617
Inventory holding (gains) losses	**3**	(51)	–
Replacement cost profit before interest and tax	**3,373**	4,134	2,617
Net charge (credit) for non-operating items[b]	**(246)**	–	–
Underlying replacement cost profit before interest and tax[c]	**3,127**	4,134	2,617

[a] The TNK-BP segment includes equity-accounted earnings from associates, in which all amounts shown relate to BP's 50% share in TNK-BP, as follows:

Profit before interest and tax	**4,405**	5,992	3,866
Finance costs	**(84)**	(132)	(128)
Taxation	**(979)**	(1,333)	(913)
Minority interest	**(356)**	(342)	(208)
Net income	**2,986**	4,185	2,617
Inventory holding (gains) losses, net of tax	**3**	(51)	–
Net income on a replacement cost basis	**2,989**	4,134	2,617
Net charge (credit) for non-operating items,[b] net of tax	**138**	–	–
Net income on an underlying replacement cost basis[c]	**3,127**	4,134	2,617

[b] Disclosure of non-operating items for TNK-BP began in 2012.

[c] Underlying replacement cost profit is not a recognized GAAP measure. See footnote b on page 34 for information on underlying replacement cost profit.

	2012	2011	2010
Production (net of royalties)(BP share)[d]			
Crude oil (thousand barrels per day)	**876**	871	856
Natural gas (million cubic feet per day)	**784**	710	640
Total hydrocarbons[e] (thousand barrels of oil equivalent per day)	**1,012**	994	967
Estimated net proved reserves[d] (net of royalties)(BP share)			
Crude oil (million barrels)[f]	**4,540**	4,305	3,750
Natural gas (billion cubic feet)[g]	**4,492**	2,881	2,359
Total hydrocarbons[f g] (million barrels of oil equivalent)	**5,315**	4,802	4,157
Average oil marker prices			$ per barrel
Urals (Northwest Europe – CIF)	**110.19**	109.08	78.26
Russian domestic oil	**53.98**	49.57	36.96

[d] BP continues to report its share of TNK-BP's production and reserves until the transaction to sell its 50% share to Rosneft closes.

[e] 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.

[f] Includes 328 million barrels (310 million barrels at 31 December 2011 and 254 million barrels at 31 December 2010) in respect of the 7.35% minority interest in TNK-BP (7.37% at 31 December 2011 and 7.03% at 31 December 2010).

[g] Includes 270 billion cubic feet (174 billion cubic feet at 31 December 2011 and 137 billion cubic feet at 31 December 2010) in respect of the 6.17% minority interest in TNK-BP (6.27% at 31 December 2011 and 5.89% at 31 December 2010).

Replacement cost profit before interest and tax[h] for the TNK-BP segment was $3,373 million, compared with $4,134 million in 2011. These amounts include BP's equity-accounted share of TNK-BP's earnings. In 2012, equity-accounted earnings are included from 1 January to 21 October, after which our investment was classified as an asset held for sale and therefore equity accounting ceased.

[h] Under equity accounting, BP's share of TNK-BP's earnings after interest and tax has been included in the BP group income statement within profit before interest and tax.

The 2012 result also included a net non-operating gain of $246 million, primarily dividend income from TNK-BP of $709 million, partly offset by a charge of $325 million to settle disputes with AAR. With the cessation of equity accounting, under IFRS dividends from our investment in TNK-BP are recognized as revenue in the period in which they become receivable. In addition, within equity-accounted earnings, there was an impairment loss associated with the temporary shutdown of the Lisichansk refinery in the Ukraine (due to deteriorating economic conditions) and environmental provisions, partly offset by gains on disposals. Prior to 2012, non-operating items for the TNK-BP segment were not identified or disclosed.

After adjusting for non-operating items, the underlying replacement cost profit before interest and tax[a b] for the TNK-BP segment was $3,127 million, compared with $4,134 million in 2011. The primary factors impacting the 2012 result, compared with 2011, were the absence of more than two months of equity-accounted earnings, lower realizations and the impact of the tax reference price lag on Russian export duties in falling price environments, partly offset by positive foreign exchange effects.

BP received $1,399 million in cash dividends from its investment in TNK-BP in 2012, as compared with $3,747 million during 2011. This included $709 million received after reaching agreement with Rosneft for the sale of BP's shareholding in TNK-BP.

[a] Underlying replacement cost profit is not a recognized GAAP measure. See footnote b on page 34 for information on underlying replacement cost profit.
[b] See footnote h on page 80.

Production and reserves

BP's share of TNK-BP production for the full year of 2012 was 1,012mboe/d, 2% higher than in 2011. After adjusting for the effect of the acquisition of BP's upstream interests in Vietnam and Venezuela, production increased only slightly compared with 2011, with the ramp-up of new developments offsetting declines from mature fields and the impact of divestments.

The TNK-BP segment's total hydrocarbon reserves, on an oil equivalent basis, was 5,315mmboe at 31 December 2012, an increase of 11% (increase of 5% for crude oil and increase of 56% for natural gas), compared with the 31 December 2011 reserves of 4,802mmboe.

The proved reserves replacement ratio is the extent to which production is replaced by proved reserves additions. For 2012, the proved reserves replacement ratio excluding acquisitions and disposals was 242% (2011 245%, 2010 165%). For more information on proved reserves replacement for the group, see pages 85-86.

Key business events

On 11 March, TNK-BP announced the acquisition of two companies that operate the jet fuel storage and re-fuelling services at the Koltsovo International Airport in Ekaterinburg. The airport is the fifth largest in the Russian Federation in terms of number of passengers.

On 21 May, TNK-BP announced the appointment of Evert Henkes to the board of TNK-BP Ltd as a BP-nominated independent director. He became the tenth member of the board of TNK-BP Ltd and the second of the board's three independent directors. This appointment followed the resignations of Gerhard Schroeder and James Leng.

On 28 May, TNK-BP announced that Mikhail Fridman had resigned from the position of chief executive officer of the TNK-BP group. He also resigned from the position of chairman of the management board of TNK-BP Management, a Russian subsidiary of TNK-BP, which manages the company's assets in Russia and Ukraine, including the publicly traded company, TNK-BP Holding. Both resignations took effect at the end of June 2012.

On 20 August, TNK-BP announced that it had sold OJSC Novosibirskneftegaz and OJSC Severnoeneftegaz as part of the company's strategy to optimize the asset portfolio and improve per barrel efficiency.

On 9 October, TNK-BP announced that the group's subsidiary, TNK Vietnam, had produced the first gas from the Lan Do field in Block 06.1, offshore of Ba Ria Vung Tau province. Two sub-sea wells were tied back to the Lan Tay platform, through 28 kilometres of flow line and umbilical, enabling TNK Vietnam to produce gas from the existing infrastructure. The Lan Do field is expected to bring 2 billion cubic metres (70 billion cubic feet) of gas to market annually.

On 13 November, BP and AAR announced they had reached an agreement to settle all outstanding disputes between them, including the arbitrations brought by each against the other. The agreement included a waiver of the new opportunities provision in the TNK-BP shareholder agreement, allowing each party to explore new opportunities and partnerships in Russia and Ukraine. BP paid AAR $325 million as part of the settlement. See Legal proceedings on pages 169-171 for further information.

Other businesses and corporate

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

The replacement cost loss before interest and tax for the year ended 31 December 2012 was $2,795 million, compared with $2,478 million for the previous year. 2012 included a net charge for non-operating items of $798 million. (See page 37 for further information on non-operating items.)

After adjusting for non-operating items, the underlying replacement cost loss before interest and tax for the year ended 31 December 2012 was $1,997 million compared with $1,656 million in 2011. The 2012 result was impacted by the loss of income from the sale of the aluminium business in 2011, adverse foreign exchange effects and higher corporate and functional costs.

The replacement cost loss before interest and tax for the year ended 31 December 2011 included a net charge for non-operating items of $822 million.

The replacement cost loss before interest and tax for the year ended 31 December 2010 included a net charge for non-operating items of $200 million.

The primary additional factors reflected in 2011's result compared with that of 2010 were weaker business performance and higher corporate costs, offset by more favourable foreign exchange effects and cost efficiencies.

			$ million
	2012	2011	2010
Sales and other operating revenues[a]	**1,985**	2,957	3,328
Replacement cost (loss) before interest and tax	**(2,795)**	(2,478)	(1,516)
Net (favourable) unfavourable impact of non-operating items	**798**	822	200
Underlying replacement cost profit (loss) before interest and tax[b]	**(1,997)**	(1,656)	(1,316)
Capital expenditure and acquisitions	**1,435**	1,853	1,234

[a] Includes sales between businesses.

[b] Underlying replacement cost profit (loss) is not a recognized GAAP measure. See footnote b on page 34 for information on underlying replacement cost profit.

Alternative Energy

Alternative Energy comprises BP's lower-carbon businesses and future growth options outside oil and gas. These are biofuels, wind and a range of other longer-term technology investments.

Market commentary

A more diverse mix of energy will be required to meet long-term future demand. BP's own estimates suggest that global primary energy demand will increase by around 1.6% per annum between 2010 and 2030. Supported by government policies, renewables' global share of power generation is expected to be 11% by 2030. Through 2030, biofuels are expected to account for 13% of transport energy demand growth[a].

[a] *BP Energy Outlook 2030.*

2012 performance

Alternative Energy continues to deliver on its mission to invest in and develop new, material sources of lower-carbon energy that are in alignment with BP's core capabilities.

In 2012 our wind business brought three new wind farms into operation, bringing its total to 16 operating farms in nine US states. Across our wind facilities, BP's net share of wind generation for 2012 was 3,587GWh (5,739GWh gross), compared with 2,394GWh (4,309GWh gross) a year ago. Additional projects continue to be evaluated.

Globally, BP has continued to increase its biofuels production. In Hull, UK, we have commissioned the joint venture Vivergo ethanol facility with a production capacity of 420 million litres per year. In Brazil, BP is progressing expansion of its ethanol production at its existing three sugar cane ethanol mills. In conjunction with joint venture partner DuPont, BP is undertaking leading edge research into the production of biobutanol under the company name Butamax.

Across our biofuels business, BP's net share of ethanol-equivalent production for 2012 was 404 million litres compared with 314 million litres (410 million litres gross)[b] a year ago. The majority of this production is from BP's sugar cane mills in Brazil.

In the US, BP has made the strategic decision to focus its biofuels business on the research, development, and commercialization of cellulosic ethanol technology at its facilities in San Diego, California, and Jennings, Louisiana.

Alternative Energy has now invested approximately $7.6 billion[c], investing at a faster pace than its 2005 commitment of $8 billion over 10 years.

[b] BP acquired the remaining 50% of Tropical Bioenergia on 22 November 2011.

[c] The majority of costs were initially capitalized, although some were expensed under IFRS.

Biofuels

BP believes that it has a key technological 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 on the most efficient transformation of sustainable and low-cost sugars into a range of fuel molecules. Our strategy is to focus on the conversion of cost-advantaged feedstocks that are materially scalable and that can be competitive in an $80 crude oil environment without subsidies.

To this end, BP now operates three sugar cane mills in Brazil producing bioethanol, sugar and exporting power to the grid. We continue to evaluate options to increase production at these facilities. Likewise, through the joint venture Vivergo, we are operating the largest bioethanol facility in the UK, and one of the largest in Europe. At 420 million litres per year, the Vivergo facility represents around a third of the UK's 2012-13 requirements under the Renewable Transport Fuels Obligation (RTFO). In addition, once Vivergo is at full production, it is set to become the largest source of animal feed in the UK.

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, which has a higher energy content than ethanol and delivers improved fuel economy. See Technology on pages 57-59 for further information.

Wind

In wind power, BP has focused its business onshore in the US. BP has an interest in 16 wind farms located in nine US states: California (1), Colorado (2), Hawaii (1), Idaho (1), Indiana (3), Kansas (2), Pennsylvania (1), South Dakota (1) and Texas (4).

During 2012, together with our partners, we completed construction of wind farms in Kansas, Pennsylvania and Hawaii. We have created nearly 4,300 construction jobs and more than 200 jobs operating wind farms since creation of our wind business.

BP increased its net wind generation capacity in the US to 1,558MW[d] during 2012, an increase of over 50% compared with the end of the prior year.

[d] BP also has 32MW of wind capacity in the Netherlands, operated by Downstream.

Solar

The exit of our solar business as announced in December 2011 has been substantially completed.

Emerging business and ventures

Our emerging business and ventures unit brings together BP's venturing and carbon markets expertise with our carbon capture and storage capability. Through this unit, we have invested more than $175 million across 33 separate investments spanning the following areas: bioenergy, energy efficiency and storage, carbon management, renewable power and, more recently, in emerging oil and gas technologies. These investments provide BP with insight and access to cutting-edge technologies that can help make the company more efficient, productive, sustainable and profitable. See Technology on pages 57-59 for further information.

Our carbon capture and storage expertise is helping our businesses understand and manage their CO_2 emissions, and to monitor CO_2 storage opportunities, such as the In Salah gas field where we have injected almost 4 million tonnes of CO_2 since 2004. Presently, CO_2 injection at the storage site is suspended while the In Salah Gas joint venture partners (BP, Sonatrach and Statoil) evaluate the large body of data acquired during the first phase of operation.

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

At the end of 2012, we had 52 international vessels (37 medium-size crude and product carriers, three very large crude carriers, one North Sea shuttle tanker, eight LNG carriers and three 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.

In December 2012 BP announced it had signed a contract with STX Offshore and Shipbuilding to build 13 new tankers in Korea. The first of these will be delivered in late 2014.

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 four offshore support vessels each one complete with two autonomous rescue and recovery crafts).

Time-charter vessels

At the end of 2012 BP had 111 hydrocarbon-carrying vessels above 600 deadweight tonnes on time-charter, all of which are double-hulled. The quality and safety performance of these vessels is assured through BP's Time Charter Assurance Programme.

Spot-charter vessels

BP spot-charters vessels, typically for single voyages. These vessels are always assessed against BP's marine assurance requirements prior to each 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.

Maritime security issues

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

2012 has seen continuing pirate activity in the Gulf of Aden, the Indian Ocean (up to approximately 200 miles west of the Indian coast) and the Arabian Sea. It should however be noted that pirate activity has reduced considerably compared with previous years. This decrease in activity is due principally to more robust intervention by the various navies operating in this region and to greater adoption of protective measures by vessels transiting these waters.

At present, we follow available military and government agency advice and are participating in protective group transits through the Gulf of Aden Internationally Recommended Transit Corridor. BP uses the protective measures recommended in the international shipping industry guide *BMP 4 – Best Management Practices for Protection against Somalia Based Piracy,* jointly published by industry bodies, including Oil Companies International Marine Forum and supported by military operations in the region.

We continue to monitor other areas where cargo piracy is known to occur, for example West Africa and the South China Sea.

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 cash flows. Trading activities are underpinned by the compliance, control and risk management infrastructure common to all BP trading activities. For further information, see Financial statements – Note 26 on page 220.

Insurance

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. Losses are borne as they arise, rather than being spread over time through insurance premiums with attendant transaction costs. This approach was reviewed following the Deepwater Horizon oil spill but the group concluded that it will continue with its current approach of not generally purchasing insurance cover.

Oil and gas disclosures for the group

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 five 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 and additional reservoir development activity.

Volumes can also be added or removed from our portfolio through acquisition or divestment of properties and projects. When we dispose of an interest in a property or project, the volumes associated with our adopted plan of development for which we have a final investment decision will be removed from our proved reserves upon completion. When we acquire an interest in a property or project, the volumes associated with the existing development and any committed projects will be added to our proved reserves if BP has made a final investment decision and they satisfy the SEC's criteria for attribution of proved status. Following the acquisition, additional volumes may be progressed to proved reserves from contingent.

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. BP will only book proved reserves where development is scheduled to commence after more than five years, if these proved reserves satisfy the SEC's criteria for attribution of proved status and BP management has reasonable certainty that these proved reserves will be produced.

At the end of 2012, BP had material volumes of proved undeveloped reserves held for more than five years in Trinidad, as well as non-material volumes in Angola, Australia, Azerbaijan, Russia, the UK and the US, that are part of ongoing development activities for which BP has a historical track record of completing comparable projects in these countries.

The volumes are being progressed as part of an adopted development plan where there are physical limits to the development timing such as infrastructure limitations, contractual limits including gas delivery commitments, late life compression and the complex nature of working in remote locations.

Over the past five years, BP has annually progressed on average about 20% of our proved undeveloped reserves (excluding disposals) to proved developed reserves. This equates to a turnover time of about five years. We expect the turnover time to remain at or below five years and anticipate the volume of proved undeveloped reserves held for more than five years to remain about the same.

In 2012 we progressed 1,279mmboe of proved undeveloped reserves (780mmboe for our subsidiaries alone) to proved developed reserves through ongoing investment in our upstream development activities. Total development expenditure in Upstream, excluding midstream activities, was $15,247 million in 2012 ($11,964 million for subsidiaries and $3,283 million for equity-accounted entities). The major areas with progressed volumes in 2012 were Angola, Azerbaijan, Iraq, Norway, Russia, Trinidad and the US. Revisions of previous estimates for proved undeveloped reserves are due to the impact of year-end price (net reduction of 33%) and changes relating to field performance or well results (67%). The following tables describe the changes to our proved undeveloped reserves position through the year for our subsidiaries and equity-accounted assets and for our subsidiaries alone.

Subsidiaries and equity-accounted assets	volumes in mmboe
Proved undeveloped reserves at 1 January 2012	7,919
Revisions of previous estimates	(95)
Improved recovery	586
Discoveries and extensions	462
Purchases	49
Sales	(116)
Total in year proved undeveloped reserves changes	8,805
Progressed to proved developed reserves	(1,279)
Proved undeveloped reserves at 31 December 2012	7,526

Subsidiaries only	volumes in mmboe
Proved undeveloped reserves at 1 January 2012	5,378
Revisions of previous estimates	(700)
Improved recovery	496
Discoveries and extensions	169
Purchases	49
Sales	(108)
Total in year proved undeveloped reserves changes	5,284
Progressed to proved developed reserves	(780)
Proved undeveloped reserves at 31 December 2012	4,504

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 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.
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 is to consider whether the group's system of internal control is adequately designed and operating effectively to respond appropriately to the risks that are significant to BP.
- 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. In addition, BP commenced a review of certain of its assets and estimation processes. This review process will continue through 2013.

BP's vice president of segment reserves is the petroleum engineer primarily responsible for overseeing the preparation of the reserves estimate. He has nearly 30 years of diversified industry experience with the past eight spent managing the governance and compliance of BP's reserves estimation. He is a past member of the Society of Petroleum Engineers Oil and Gas Reserves Committee, a sitting member of the American Association of Petroleum Geologists Committee on Resource Evaluation and chair of the bureau of 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 Upstream 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 Upstream 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.

Compliance

International Financial Reporting Standards (IFRS) 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.

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 our entitlement to the hydrocarbons is calculated using a more complex formula, such as with 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.

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.

BP's estimated net proved reserves and proved reserves replacement

Eighty-two per cent of our total proved reserves of subsidiaries at 31 December 2012 were held through unincorporated joint ventures (75% in 2011), and 31% of the proved reserves were held through such unincorporated joint ventures where we were not the operator (33% in 2011).

Estimated net proved reserves of liquids at 31 December 2012[a b c]

			million barrels
	Developed	Undeveloped	Total
UK	242	431	673
Rest of Europe	170	79	249
US	1,443	989	2,432[d]
Rest of North America	–	–	–
South America	22	32	54[e]
Africa	312	255	567
Rest of Asia	268	137	405
Australasia	52	45	97
Subsidiaries	2,509	1,968	4,477[f]
Equity-accounted entities	3,041	2,532	5,573[g h]
Total	5,550	4,500	10,050

Estimated net proved reserves of natural gas at 31 December 2012[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	1,038	666	1,704
Rest of Europe	340	141	481
US	8,245	2,986	11,231
Rest of North America	4	–	4
South America	3,588	6,250	9,838[i]
Africa	1,139	1,923	3,062
Rest of Asia	926	413	1,339
Australasia	3,282	2,323	5,605
Subsidiaries	18,562	14,702	33,264[f]
Equity-accounted entities	4,196	2,845	7,041[g h]
Total	22,758	17,547	40,305

Net proved reserves on an oil equivalent basis

			million barrels of oil equivalent
	Developed	Undeveloped	Total
Subsidiaries	5,709	4,504	10,213[f]
Equity-accounted entities	3,765	3,022	6,787[g]
Total	9,474	7,526	17,000

[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 2012 marker prices used were Brent $111.13/bbl (2011 $110.96/bbl and 2010 $79.02/bbl) and Henry Hub $2.75/mmBtu (2011 $4.12/mmBtu and 2010 $4.37/mmBtu).

[c] Liquids include crude oil, condensate, natural gas liquids and bitumen.

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 76 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.

[e] Includes 14 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[f] Includes assets held for sale of 39 million barrels of liquids and 590 billion cubic feet of natural gas (140 million barrels of oil equivalent).

[g] Includes assets held for sale of 4,540 million barrels of liquids and 4,492 billion cubic feet of natural gas (5,315 million barrels of oil equivalent) associated with TNK-BP.

[h] Includes 328 million barrels of liquids and 270 billion cubic feet of natural gas in respect of the 7.35% and 6.17% minority interests respectively in TNK-BP.

[i] Includes 2,890 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

Proved reserves replacement

Total hydrocarbon proved reserves, on an oil equivalent basis including equity-accounted entities, comprised 17,000mmboe (10,213mmboe for subsidiaries and 6,787mmboe for equity-accounted entities) at 31 December 2012, a decrease of 4% (decrease of 11% for subsidiaries and increase of 7% for equity-accounted entities) compared with the 31 December 2011 reserves of 17,748mmboe (11,426mmboe for subsidiaries and 6,322mmboe for equity-accounted entities). Natural gas represented about 41% (56% for subsidiaries and 18% for equity-accounted entities) of these reserves. The change includes a net decrease from acquisitions and disposals of 455mmboe (440mmboe net decrease for subsidiaries and 15mmboe net decrease for equity-accounted entities). Additions from acquisitions occurred principally in the US following a 2011 acquisition. Divestments occurred in Norway, Russia, Trinidad, the UK and the US.

Proved reserves contain volumes in assets held for sale of 39 million barrels of liquids and 590 billion cubic feet of natural gas (140 million barrels of oil equivalent) in our subsidiaries and 4,540 million barrels of liquids and 4,492 billion cubic feet of natural gas (5,315 million barrels of oil equivalent) associated with TNK-BP.

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. For 2012, the proved reserves replacement ratio excluding acquisitions and disposals was 77% (103% in 2011 and 106% in 2010) for subsidiaries and equity-accounted entities, -5% for subsidiaries alone and 195% for equity-accounted entities alone.

In 2012, net additions to the group's proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 953mmboe (-35mmboe for subsidiaries and 988mmboe for equity-accounted entities), through revisions to previous estimates, improved recovery from, and extensions to, existing fields and discoveries of new fields. The subsidiary additions through improved recovery from, and extensions to, existing fields and discoveries of new fields were in existing developments where they represented a mixture of proved developed and proved undeveloped reserves. Volumes added in 2012 principally resulted from the application of conventional technologies. The principal proved reserves additions in our subsidiaries were in Angola, Azerbaijan, India and Trinidad. We had material proved reserves reductions in Norway and the US due to price changes, changes in activity and performance updates. The principal reserves additions in our equity-accounted entities were in Angola, Argentina and Russia.

Twelve per cent of our proved reserves are associated with PSAs. The countries in which we operated under PSAs in 2012 were Algeria, Angola, Azerbaijan, Egypt, India, Indonesia, Oman, Vietnam and a non-material volume in Trinidad. In addition, the technical service contract (TSC) governing our investment in the Rumaila field in Iraq functions as a PSA.

The Abu Dhabi onshore concession expires in January 2014 with a consequent reduction in production of approximately 140mb/d. The group holds no other licences due to expire within the next three years that would have a significant impact on BP's reserves or production.

For further information on our reserves see page 263.

BP's net production by major field – liquids

				thousand barrels per day
Subsidiaries				BP net share of production[a]
	Field or area	**2012**	2011	2010
UK[b]	ETAP[c]	**11**	22	28
	Foinaven (BP-operated)	**14**	26	24
	Other[d]	**61**	65	85
Total UK		**86**	113	137
Norway[b]	Various	**23**	32	40
Total Rest of Europe		**23**	32	40
Total Europe		**109**	145	177
Alaska	Prudhoe Bay (BP-operated)	**77**	78	81
	Kuparuk	**36**	39	42
	Milne Point (BP-operated)	**15**	19	23
	Other	**11**	17	20
Total Alaska		**139**	153	166
Lower 48 onshore[b]	Various	**60**	69	90
Gulf of Mexico deepwater[b]	Thunder Horse (BP-operated)	**49**	77	120
	Atlantis (BP-operated)	**23**	34	49
	Mad Dog (BP-operated)	**9**	8	30
	Mars	**15**	19	23
	Na Kika (BP-operated)	**21**	14	25
	Horn Mountain (BP-operated)	**6**	8	14
	King (BP-operated)	**14**	15	21
	Other	**54**	56	56
Total Gulf of Mexico deepwater		**191**	231	338
Total US		**390**	453	594
Canada[b]	Various (BP-operated)	**1**	2	7
Total Rest of North America		**1**	2	7
Total North America		**391**	455	601
Colombia[b]	Various (BP-operated)	**–**	1	18
Trinidad & Tobago	Various (BP-operated)	**21**	31	36
Brazil[b]	Polvo (BP-operated)	**7**	7	–
Total South America		**28**	39	54
Angola	Greater Plutonio (BP-operated)	**59**	51	73
	Kizomba C Dev	**9**	21	31
	Dalia	**11**	12	20
	Girassol FPSO	**11**	12	18
	Pazflor	**29**	5	–
	Other	**30**	22	28
Total Angola		**149**	123	170
Egypt[b]	Gupco	**32**	34	47
	Other	**9**	11	12
Total Egypt		**41**	45	59
Algeria[b]	Various	**12**	22	17
Total Africa		**202**	190	246
Azerbaijan[b]	Azeri-Chirag-Gunashli (BP-operated)	**82**	86	94
	Other	**10**	8	9
Total Azerbaijan		**92**	94	103
Western Indonesia[b]	Various	**1**	2	2
Iraq	Rumaila	**39**	31	–
Other	Various	**7**	11	14
Total Rest of Asia[b]		**139**	138	119
Total Asia		**139**	138	119
Australia	Various	**24**	23	30
Other	Various	**3**	2	2
Total Australasia		**27**	25	32
Total subsidiaries[e]		**896**	992	1,229
Equity-accounted entities (BP share)				
Russia – TNK-BP[b]	Various	**863**	865	856
Total Russia		**863**	865	856
Abu Dhabi[f]	Various	**216**	209	190
Other	Various	**1**	1	1
Total Rest of Asia[b]		**217**	210	191
Total Asia		**1,080**	1,075	1,047
Argentina	Various	**65**	74	75
Venezuela[b]	Various	**14**	16	23
Bolivia[b]	Various	**1**	–	–
Total South America		**80**	90	98
Total equity-accounted entities[g]		**1,160**	1,165	1,145
Total subsidiaries and equity-accounted entities		**2,056**	2,157	2,374

[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 2012, BP divested its interests in the US Gulf of Mexico Marlin, Dorado, King, Horn Mountain, Holstein, Ram Powell and Diana Hoover assets, a portion of our interest in US Gulf of Mexico Mad Dog asset, its interests in the US onshore Jonah and Pinedale upstream operation in Wyoming, and associated gas gathering system, its interests in the Canadian natural gas liquid business, its interests in the Alba and Britannia fields in the UK North Sea, its interests in the Draugen field in the Norwegian Sea, and TNK-BP disposed of its interests in OJSC Novosibirskneftegaz, with interests in Novosibirsk region, Omsk region, and Irkutsk region, and its interests in OJSC Severnoeneftegaz, with interests in Novosibirsk region. BP also increased its interest in the US onshore Eagle Ford Shale in south Texas, its interests in certain UK North Sea assets, and in certain US Alaska assets. In 2011, BP sold its holdings in Venezuela and Vietnam to TNK-BP. It also made acquisitions in India through a joint venture with Reliance, Brazil and additional volumes in the US Gulf of Mexico and UK North Sea. BP divested its holdings in Pompano along with other interests in the US Gulf of Mexico, Tuscaloosa and interests in South Texas in the US onshore, a portion of our interest in the Azeri-Chirag-Gunashli development in Azerbaijan, Wytch Farm in the UK, our interests in the REB field in Algeria, and the remainder of our interests in Colombia and Pakistan. In 2010, BP divested its Permian Basin assets in Texas and south-east New Mexico, the East Badr El-Din and Western Desert concession in Egypt, its Canada gas assets and reduced its interest in the King field in the Gulf of Mexico. It also acquired an increased holding in the Azeri-Chirag-Gunashli development in Azerbaijan and the Valhall and Hod fields in the Norwegian North Sea. Four other producing fields in the Gulf of Mexico that were acquired during 2010 were subsequently disposed of in early 2011.

[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] 2012 includes 17mb/d of production in assets held for sale.

[e] Includes 13.5 net mboe/d of NGLs from processing plants in which BP has an interest (2011 28mboe/d and 2010 29mboe/d).

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

[g] 2012 includes 877mb/d of production in assets held for sale associated with TNK-BP. See TNK-BP on pages 80-81 for further information.

BP's net production by major field – natural gas

				million cubic feet per day
Subsidiaries				BP net share of production[a]
	Field or area	**2012**	2011	2010
UK[b]	Bruce/Rhum (BP-operated)	**15**	20	100
	Other[c]	**399**	335	372
Total UK		**414**	355	472
Norway[b]	Various	**8**	13	15
Total Rest of Europe		**8**	13	15
Total Europe		**422**	368	487
Lower 48 onshore[b]	San Juan (BP-operated)	**561**	603	629
	Jonah (BP-operated)	**69**	145	185
	Anadarko	**142**	141	137
	Arkoma Central	**118**	136	164
	Wamsutter (BP-operated)	**141**	122	126
	Arkoma East	**112**	115	112
	Arkoma West	**98**	109	128
	Other	**258**	274	394
Total Lower 48 onshore	Total	**1,499**	1,645	1,875
Gulf of Mexico deepwater[b]	Various	**134**	176	263
Alaska	Various	**18**	22	46
Total US		**1,651**	1,843	2,184
Canada[b]	Various	**13**	14	202
Total Rest of North America		**13**	14	202
Total North America		**1,664**	1,857	2,386
Trinidad & Tobago	Mango (BP-operated)	**181**	308	544
	Cashima/NEQB (BP-operated)	**305**	570	679
	Kapok (BP-operated)	**360**	464	541
	Cannonball (BP-operated)	**56**	99	156
	Amherstia (BP-operated)	**324**	296	252
	Serrette (BP-operated)	**367**	35	–
	Savonette (BP-operated)	**320**	327	203
	Other (BP-operated)	**184**	94	98
Total Trinidad		**2,097**	2,193	2,473
Colombia[b]	Various	**–**	4	71
Total South America		**2,097**	2,197	2,544
Egypt[b]	Temsah	**34**	74	90
	Ha'py (BP-operated)	**88**	99	73
	Taurt (BP-operated)	**67**	61	75
	Other	**281**	210	192
Total Egypt		**470**	444	430
Algeria	Various	**120**	114	126
Total Africa		**590**	558	556
Pakistan[b]	Various (BP-operated)	**–**	73	150
Azerbaijan[b]	Various (BP-operated)	**158**	140	132
Western Indonesia[b]	Sanga-Sanga	**59**	59	69
	Other	**–**	–	1
Total Western Indonesia		**59**	59	70
India[b]	D1D3	**253**	121	–
	Other	**60**	25	–
Total India		**313**	146	–
Vietnam[b]	Various (BP-operated)	**–**	69	77
China	Yacheng	**54**	70	95
Oman		**14**	20	–
Sharjah	Various (BP-operated)	**35**	41	50
Total Rest of Asia		**633**	618	574
Total Asia		**633**	618	574
Australia	Perseus/Athena	**141**	170	165
	Goodwyn	**73**	72	118
	Angel	**110**	126	133
	Other	**111**	87	46
Total Australia		**435**	455	462
Eastern Indonesia	Tangguh (BP-operated)	**352**	340	323
Total Australasia		**787**	795	785
Total subsidiaries[d]		**6,193**	6,393	7,332
Equity-accounted entities (BP share)				
Russia – TNK-BP[b]	Various	**734**	699	640
Western Indonesia	Various	**26**	26	30
Vietnam[b]		**46**	8	–
Total Rest of Asia		**72**	34	30
Total Asia		**806**	733	670
Argentina	Various	**355**	371	379
Bolivia[b]	Various	**34**	14	11
Venezuela[b]	Various	**5**	7	9
Total South America		**394**	392	399
Total equity-accounted entities[d e]		**1,200**	1,125	1,069
Total subsidiaries and equity-accounted entities		**7,393**	7,518	8,401

[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 2012, BP divested its interests in the US Hugoton basin including the Jayhawk NGL plant, its interests in US Gulf of Mexico Marlin, Dorado, King, Horn Mountain, Holstein, Ram Powell and Diana Hoover assets, a portion of our interest in US Gulf of Mexico Mad Dog asset, its interests in the US onshore Jonah and Pinedale upstream operation in Wyoming, its interests in the Sunray and Hemphill gas processing plants in Texas, and associated gas gathering system, its interests in the UK North Sea southern gas fields including associated pipeline infrastructure and the Dimlington terminal (including the integrated Easington terminal), and its interests in the Alba and Britannia fields in the UK North Sea. BP also increased its interest in the US onshore Eagle Ford Shale in South Texas, and its interests in certain UK North Sea assets. In 2011, BP sold its holdings in Venezuela and Vietnam to TNK-BP. It also made acquisitions in India through a joint venture with Reliance, in the Eagle Ford shale in North America and additional volumes in the US Gulf of Mexico. BP divested its holdings in Pompano along with other interests in the US Gulf of Mexico, Tuscaloosa and interests in south Texas in the US onshore, Wytch Farm in the UK, minor volumes in Canada and the remainder of our interests in Colombia and Pakistan. In 2010, BP divested its Permian Basin assets in Texas and south-east New Mexico, the East Badr El-Din concession in Egypt, its Canada gas assets and reduced its interest in the King field in the Gulf of Mexico. It also acquired an increased holding in the Valhall and Hod fields in the Norwegian North Sea. Four other producing fields in the Gulf of Mexico that were acquired during 2010 were subsequently disposed of in early 2011.

[c] 2012 includes 40mmcf/d of production in assets held for sale.

[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.

[e] 2012 includes 785mmcf/d of production in assets held for sale associated with TNK-BP. See TNK-BP on pages 80-81 for further information.

The following tables provide additional data and disclosures in relation to our oil and gas operations.

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[b]			Russia	Rest of Asia		
Average sales price[c]										
Subsidiaries										
2012										
Liquids[d]	**109.64**	**106.93**	**96.35**	**–**	**84.53**	**106.39**	**–**	**109.69**	**103.12**	**102.10**
Gas	**8.62**	**9.43**	**2.32**	**–**	**3.53**	**6.05**	**–**	**5.08**	**10.08**	**4.75**
2011										
Liquids[d e]	106.89	107.83	96.34	–	86.60	104.37	–	111.10	101.22	101.29
Gas	7.91	13.15	3.34	–	3.60	5.24	–	4.73	9.13	4.69
2010										
Liquids[d]	76.33	81.09	70.79	48.26	71.01	74.87	–	78.80	75.81	73.41
Gas	5.44	7.16	3.88	4.20	2.80	4.11	–	4.05	7.01	3.97
Equity-accounted entities[f]										
2012										
Liquids[d]	**–**	**–**	**–**	**–**	**79.08**	**–**	**83.85**	**10.15**	**–**	**69.41**
Gas	**–**	**–**	**–**	**–**	**2.35**	**–**	**2.35**	**5.08**	**–**	**2.52**
2011										
Liquids[d]	–	–	–	–	73.51	–	84.39	8.11	–	71.35
Gas	–	–	–	–	2.31	–	2.23	12.21	–	2.40
2010										
Liquids[d]	–	–	–	–	61.60	–	60.39	6.72	–	52.81
Gas	–	–	–	–	1.97	–	1.91	7.83	–	2.04

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

[b] Producing assets now largely divested.

[c] Realizations include transfers between businesses.

[d] Crude oil and natural gas liquids.

[e] A minor amendment has been made to 2011 realizations for UK and Europe.

[f] It is common for equity-accounted entities' agreements to include pricing clauses that require selling a significant portion of the entitled production to local governments or markets at discounted prices.

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[b]			Russia	Rest of Asia		
The average production cost per unit of production[a]										
Subsidiaries										
2012	**22.77**	**39.10**	**15.60**	**–**	**5.69**	**11.89**	**–**	**11.85**	**3.23**	**12.50**
2011	21.59	18.23	12.09	–	3.20	10.82	–	8.65	3.05	10.08
2010	12.79	9.76	8.10	15.78	2.48	7.52	–	4.59	2.03	6.77
Equity-accounted entities										
2012	**–**	**–**	**–**	**–**	**11.33**	**–**	**5.72**	**2.88**	**–**	**5.76**
2011	–	–	–	–	9.04	–	5.68	2.70	–	5.58
2010	–	–	–	–	6.32	–	5.04	2.61	–	4.83

[a] Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

[b] Producing assets now largely divested.

Liquidity and capital resources

Since the Gulf of Mexico oil spill in 2010 and the significant costs relating to the response activities and the initial uncertainty regarding the ultimate magnitude of its liabilities and timing of cash outflows, the group's situation has continued to stabilize. This has been reflected in the group's liquidity and capital resources position, which has continued to be strengthened as well as put on a stable footing, underpinned by a prudent financial framework.

The group's long-term credit ratings are A (positive outlook) from Standard & Poor's, strengthened from A (stable outlook) in July 2012, and A2 (stable outlook) from Moody's Investor Services.

BP renegotiated its committed bank facilities during early 2011, putting in place $6.8 billion of facilities with 23 international banking counterparties for a term of three years. In addition the group has continued to strengthen its access to commercial bank letters of credit (LC) and at the end of 2012 has in place committed LC facilities of $6.9 billion and secured LC arrangements of $2.2 billion, to supplement its uncommitted and unsecured LC lines.

The disposal programme for $38 billion has been essentially completed a year ahead of schedule, including $15 billion during 2012. Cash receipts of $11.4 billion were received in 2012, following $2.7 billion of receipts in 2011 and $17.0 billion in 2010.

In addition, we will benefit from further financial flexibility when we complete the sale of BP's 50% share in TNK-BP to Rosneft, as announced early in the fourth quarter of 2012, in return for cash and shares. Having already received $709 million in December as a dividend from TNK-BP, we expect to receive a further net $11.6 billion cash on completion, which is anticipated in the first half of 2013. At that time our shareholding in Rosneft will increase from 1.25% to 19.75%.

During 2012 BP completed the payments into the Deepwater Horizon Oil Spill Trust that have totalled $20 billion.

BP accessed US, European and Australian capital markets throughout the year with bond issuances amounting to $11 billion in 2012.

During 2012 BP repaid the remaining balance of $2.3 billion on the $4.5 billion of borrowings raised in 2010 that were backed by future crude oil sales from BP's interests in specific offshore Angola and Azerbaijan fields.

Financial framework

BP continues to refine its financial framework to support the pursuit of value growth for shareholders, while maintaining a secure financial base. BP intends to increase operating cash flow[a] by around 50% in 2014 compared with 2011[b], and thereafter maintain focus on growing sustainable free cash flows[c]. The improvement in operating cashflow to 2014 will be delivered partly from the removal of quarterly trust fund payments of $1.25 billion after completion in 2012, and partly through high-margin projects coming onstream. The growth in operating cashflow will be utilized to increase both organic reinvestment and shareholder distributions.

The financial framework remains prudent and we expect to operate within a gearing[d] range of 10-20%, and to be robust to cash break-even levels in an oil price environment between $80 and $100 per barrel. BP expects to continue to maintain a significant liquidity buffer while uncertainties remain.

Dividends and other distributions to shareholders

BP aims to have a progressive dividend policy through the focus on increasing sustainable free cash flows. In addition, BP has committed to offset any dilution to earnings per share from the Rosneft transaction through either share buybacks or share consolidation.

Since BP resumed dividend payments following the suspension of dividend payments for the first three quarters of 2010 relating the Gulf of Mexico oil spill and the commitments to the Trust Fund, the dividend has been steadily increased. A quarterly dividend of 7 cents per share was paid in 2011, and increased to 8 cents per share from the first quarter 2012 to the third quarter 2012, and increased again to 9 cents per share for payment in the fourth quarter 2012.

On 5 February 2013, BP announced a dividend of 9 cents per share in respect of the fourth quarter 2012.

The total dividend paid to BP shareholders in cash in 2012 was $5.3 billion with shareholders also having the option to receive a scrip dividend, compared with $4.1 billion cash dividend paid in 2011. The dividend is determined in US dollars, the economic currency of BP.

During 2012 and 2011, the company did not repurchase any of its own shares. Details of purchases to satisfy requirements of certain employee share-based payment plans are set out on page 158.

Financing the group's activities

The group's principal commodity, oil, is priced internationally in US dollars. Group policy has generally been to minimize economic exposure to currency movements by financing operations with US dollar debt. Where debt is issued in other currencies, including euros, it is generally swapped back to US dollars using derivative contracts, or else hedged by maintaining offsetting cash positions in the same currency. The overall cash balances of the group are mainly held in US dollars or swapped to US dollars and holdings are well-diversified to reduce concentration risk. The group is not therefore exposed to significant currency risk, such as in relation to the euro, regarding its borrowings. Also see Risk factors on pages 38-44 for further information on risks associated with the general macroeconomic outlook, including the stability of the eurozone and Financial statements – Note 26 on page 220.

The group's finance debt at 31 December 2012 amounted to $48.8 billion (2011 $44.2 billion). Of the total finance debt, $10.0 billion is classified as short term at the end of 2012 (2011 $9.0 billion). The short-term balance includes $6.2 billion for amounts repayable within the next 12 months relating to long-term borrowings (2011 $4.9 billion). Commercial paper markets in the US and Europe are a further source of short-term liquidity for the group to provide timing flexibility. At 31 December 2012, outstanding commercial paper amounted to $3.0 billion (2011 $3.6 billion). Also included within short-term debt at the end of 2012 was $0.6 billion relating to deposits received for announced disposal transactions still pending legal completion post the balance sheet date (2011 $30 million).

We have in place a European Debt Issuance Programme (DIP) under which the group may raise up to $20 billion of debt for maturities of one month or longer. At 31 December 2012, the amount drawn down against the DIP was $14.0 billion (2011 $11.6 billion). The group also had in place an unlimited US shelf registration statement throughout 2012 and until 5 February 2013, under which it could raise debt with maturities of one month or longer. Following the approval in December 2012 of the SEC settlement in respect of Deepwater Horizon-related claims, the unlimited US shelf registration statement was converted to a shelf registration statement with a limit of $30 billion from 5 February 2013, with no amounts drawn down since conversion. In addition, the group has an Australian Note Issue Programme of $5 billion Australian dollars, and as at 31 December 2012 the amount drawn down was $0.5 billion Australian dollars (2011 nil).

None of the capital market bond issuances since the Gulf of Mexico oil spill contains any additional financial covenants compared with the group's capital markets issuances prior to the incident.

The maturity profile and fixed/floating rate characteristics of the group's debt are described in Financial statements – Note 34 on page 233.

Net debt was $27.5 billion at the end of 2012, a reduction of $1.5 billion from the 2011 year-end position of $29.0 billion. The ratio of net debt to net debt plus equity was 18.7% at the end of 2012 (2011 20.5%). Net debt

[a] Operating cash flow is net cash provided by (used in) operating activities, as presented in the group cash flow statement on page 185.

[b] Adjusted to remove TNK-BP dividends from 2011 and 2014 operating cash flow; 2014 includes BP's estimate of Rosneft dividend; 2014 includes the impact of payments in respect of the settlement of all federal criminal and securities claims with the US government; BP's assumption for 2014 is $100/bbl oil, $5/mmBtu Henry Hub gas. The projection does not reflect any cash flows relating to other liabilities, contingent liabilities, settlements or contingent assets arising from the Gulf of Mexico oil spill, which may or may not arise at that time. See Financial statements – Note 43 on page 253 for further information on contingent liabilities.

[c] Free cash flow is operating cash flow less net cash used in investing activities, as presented in the group cash flow statement on page 185.

[d] Gearing refers to the ratio of the group's net debt to net debt plus equity and is a non-GAAP measure. See Financial statements – Note 35 on page 234 for information on gross debt, which is the nearest equivalent measure to net debt on an IFRS basis.

and the ratio of net debt to net debt plus equity 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. See Financial statements – Note 35 on page 234 for gross debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt.

Included in net debt are cash and cash equivalents of $19.5 billion at 31 December 2012 (2011 $14.1 billion). BP manages its cash position to ensure the group has adequate cover to respond to potential short-term market illiquidity, and expects to maintain a strong cash position. Cash balances are pooled centrally where permissible, and deployed globally as required. Cash surpluses are deposited with creditworthy banks and money market funds with short maturities to ensure availability. The group holds $2 billion of cash outside the UK and it is not expected that any significant tax will arise on repatriation. Further information on the management of liquidity risk and credit risk is provided in Financial statements – Note 26 on page 220, and on the cash position in Financial statements – Note 30 on page 226.

The group also has access to significant sources of liquidity in the form of committed bank facilities. At 31 December 2012, the group had available undrawn committed standby borrowing facilities of $6.8 billion (2011 $6.9 billion) available to draw and repay by mid-March 2014.

BP believes that, taking into account the amounts of undrawn borrowing facilities and increased levels of cash and cash equivalents, and the ongoing ability to generate cash, including further disposal proceeds, the group has sufficient working capital for foreseeable requirements.

Uncertainty remains regarding the amount and timing of future expenditures relating to the Gulf of Mexico oil spill and the implications for future activities. See Risk factors on pages 38-44, and Financial statements – Note 2 on page 194, Note 36 on page 235 and Note 43 on page 253 for further information.

Off-balance sheet arrangements

At 31 December 2012, the group's share of third-party finance debt of equity-accounted entities was $6,900 million (2011 $7,003 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 2012 are $237 million (2011 $415 million) in respect of liabilities of jointly controlled entities and associates and $713 million (2011 $1,430 million) in respect of liabilities of other third parties. Of these amounts, $166 million (2011 $220 million) of the jointly controlled entities and associates guarantees relate to borrowings and for other third-party guarantees, $543 million (2011 $1,267 million) relates to guarantees of borrowings. Details of operating lease commitments, which are not recognized on the balance sheet, are shown in the table below and in Note 14 on page 211.

Contractual commitments

The following table summarizes the group's principal contractual obligations at 31 December 2012, distinguishing between those for which a liability is recognized on the balance sheet and those for which no liability is recognized. Further information on borrowings and finance leases is given in Financial statements – Note 34 on page 233 and more information on operating leases is given in Financial statements – Note 14 on page 211.

							$ million
							Payments due by period
Expected payments by period under contractual obligations and commercial commitments	Total	2013	2014	2015	2016	2017	2018 and thereafter
Balance sheet obligations							
Borrowings[a]	51,676	10,232	6,607	6,482	6,481	6,135	15,739
Finance lease future minimum lease payments	604	59	54	54	53	50	334
Decommissioning liabilities[b]	20,200	767	528	442	525	647	17,291
Environmental liabilities[b]	4,029	1,524	1,093	224	215	222	751
Pensions and other post-retirement benefits[c]	26,532	1,908	1,894	1,931	1,923	1,918	16,958
Total balance sheet obligations	103,041	14,490	10,176	9,133	9,197	8,972	51,073
Off-balance sheet obligations							
Operating lease future minimum lease payments[d]	18,459	4,531	3,494	2,666	2,007	1,566	4,195
Unconditional purchase obligations[e]	190,771	109,244	17,355	11,994	8,713	7,987	35,478
Total off-balance sheet obligations	209,230	113,775	20,849	14,660	10,720	9,553	39,673
Total	312,271	128,265	31,025	23,793	19,917	18,525	90,746

[a] Expected payments include interest payments on borrowings totalling $3,894 million ($863 million in 2013, $728 million in 2014, $607 million in 2015, $485 million in 2016, $365 million in 2017 and $846 million thereafter), and exclude disposal deposits of $632 million included in current finance debt on the balance sheet.

[b] The amounts are undiscounted. Environmental liabilities include those relating to the Gulf of Mexico oil spill, including liabilities for spill response costs.

[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] 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.

[e] 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 2013 include purchase commitments existing at 31 December 2012 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 26 on page 220.

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

							$ million
		Payments due by period					
Unconditional purchase obligations	Total	2013	2014	2015	2016	2017	2018 and thereafter
Crude oil and oil products	117,858	80,381	7,269	5,437	3,699	3,736	17,336
Natural gas	40,614	21,708	5,800	3,311	2,394	1,714	5,687
Chemicals and other refinery feedstocks	9,054	2,196	1,470	1,235	1,013	978	2,162
Power	2,769	1,830	549	194	91	86	19
Utilities	889	183	172	114	95	74	251
Transportation	13,450	1,523	1,196	1,014	910	991	7,816
Use of facilities and services	6,137	1,423	899	689	511	408	2,207
Total	190,771	109,244	17,355	11,994	8,713	7,987	35,478

The group expects its total capital expenditure, excluding acquisitions and asset exchanges, to be around $25 billion in 2013. The following table summarizes the group's capital expenditure commitments for property, plant and equipment at 31 December 2012 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.

							$ million
Capital expenditure commitments	Total	2013	2014	2015	2016	2017	2018 and thereafter
Committed on major projects	33,775	16,973	6,273	4,578	2,840	1,443	1,668
Amounts for which contracts have been placed	14,068	8,552	2,479	1,666	812	385	174

In addition, at 31 December 2012, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $465 million. Contracts were in place for $275 million of this total. The group has also signed definitive and binding sale and purchase agreements for the sale of BP's 50% interest in TNK-BP and for BP's further investment in Rosneft as described on page 80.

Cash flow

The following table summarizes the group's cash flows.

			$ million
	2012	2011	2010
Net cash provided by operating activities	**20,397**	22,154	13,616
Net cash (used in) investing activities	**(12,962)**	(26,633)	(3,960)
Net cash provided by (used in) financing activities	**(2,018)**	482	840
Currency translation differences relating to cash and cash equivalents	**64**	(492)	(279)
Increase (decrease) in cash and cash equivalents	**5,481**	(4,489)	10,217
Cash and cash equivalents at beginning of year	**14,067**	18,556	8,339
Cash and cash equivalents at end of year	**19,548**	14,067	18,556

Net cash provided by operating activities for the year ended 31 December 2012 was $20,397 million compared with $22,154 million for 2011. The cash outflow in respect of the Gulf of Mexico oil spill reduced from $6,813 million in 2011 to $2,382 million in 2012. Excluding the impacts of the Gulf of Mexico oil spill, net cash provided by operating activities was $22,779 million for 2012, compared with $28,967 million for 2011, a decrease of $6,188 million. Profit before taxation decreased by $11,269 million, of which $4,798 million related to the non-cash impacts of higher depreciation, impairments and gains and losses on disposal and lower equity-accounted earnings of jointly controlled entities and associates. A reduction in working capital requirements of $3,500 million was largely offset by lower dividends received from jointly controlled entities and associates, principally TNK-BP.

Net cash provided by operating activities for the year ended 31 December 2011 was $22,154 million compared with $13,616 million for 2010, the increase primarily reflecting a reduction in the cash outflow in respect of the Gulf of Mexico oil spill from $16,019 million in 2010 to $6,813 million in 2011. Excluding the impacts of the Gulf of Mexico oil spill, net cash provided by operating activities was $28,967 million for 2011, compared with $29,635 million for 2010, a decrease of $668 million. Profit before taxation decreased by $1,018 million, working capital requirements increased by $1,509 million and income taxes paid increased by $1,879 million. These impacts were partially offset by a decrease of $2,622 million in the net impairment, gains and losses on sale of businesses and fixed assets, and an increase in dividends received from jointly controlled entities and associates of $2,104 million.

Net cash used in investing activities was $12,962 million in 2012, compared with $26,633 million and $3,960 million in 2011 and 2010 respectively. The decrease in cash used in 2012 reflected an absence of significant expenditure on business combinations compared with 2011 when we spent $10,909 million, mainly for the Reliance and Devon acquisitions, as well as an increase in disposal proceeds of $8,714 million. This was partially offset by an increase in capital expenditure excluding acquisitions of $5,905 million. The increase in cash used in 2011 reflected a decrease of $14,222 million in disposal proceeds, including the impact of the repayment in 2011 of a $3,530-million disposal deposit received in 2010, following the termination of the Pan American Energy LLC sale agreement, and an increase of $8,441 million in acquisitions, net of cash acquired, of which $7.0 billion was for the Reliance transaction.

Net cash used in financing activities was $2,018 million in 2012 compared with net cash provided by financing activities in 2011 and 2010 of $482 million and $840 million respectively. The increase in net cash used in 2012 primarily reflected a net decrease in short-term debt of $2,901 million and an increase in dividends paid of $1,222 million, partly offset by an increase in net proceeds from long-term financing of $1,412 million. The decrease in net cash provided in 2011 primarily reflected a decrease in net proceeds from long-term financing of $4,734 million, and an increase in dividends paid of $1,445 million partly offset by a net increase in short-term debt of $5,846 million.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $24.7 billion in 2012, $18.8 billion in 2011 and $18.9 billion in 2010. 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 $27.5 billion at the end of 2012, $29.0 billion at the end of 2011 and $25.9 billion at the end of 2010.

During the period 2010 to 2012, our total sources of cash amounted to $88 billion, and our total uses of cash amounted to $88 billion. The increase in cash and cash equivalents held of $12 billion was financed by an increase in finance debt of $12 billion over the three-year period. During this period, the price of Brent crude oil has averaged $100.81 per barrel.

The following table summarizes the three-year sources and uses of cash.

	$ billion
Sources of cash:	
Net cash provided by operating activities	56
Disposals	32
	88
Uses of cash:	
Capital expenditure	62
Acquisitions	13
Net repurchase of shares	–
Dividends paid to BP shareholders	12
Dividends paid to minority interests	1
	88
Net use of cash	–
Increase in finance debt	12
Increase in cash and cash equivalents	12

Disposal proceeds received during the three-year period exceeded cash used for acquisitions, as a result in particular of our ongoing disposal programme started in 2010. Net investment (capital expenditure and acquisitions less disposal proceeds) during this period averaged $15 billion per year. Dividends paid to BP shareholders totalled $12 billion during the three-year period, with no ordinary share dividends being paid in respect of the first three quarters of 2010. In the past three years, $4 billion has been contributed to funded pension plans. This is reflected in net cash provided by operating activities in the table above.

Trend information

For information on external market trends, see Energy outlook on pages 12-14, Upstream on pages 63-71 and Downstream on pages 72-79.

We expect production in our Upstream segment to be lower in 2013 than 2012, mainly due to the impact of divestments, which we estimate at around 150mboe/d.

In Downstream, the financial impact of refinery turnarounds for 2013 is expected to be lower than in 2012. We expect the petrochemicals margins to remain under pressure during 2013.

In 2013, we expect the average quarterly charge, excluding non-operating items, for Other businesses and corporate to remain at around $500 million, although this will remain volatile between individual quarters.

We expect capital expenditure, excluding acquisitions and asset exchanges, to be around $24-25 billion as we invest to grow in the Upstream. From 2014 through to the end of the decade, we expect a range for organic capital expenditure of between $24 billion and $27 billion per annum.

Having essentially reached our $38-billion target of disposals since 2010, we expect to divest on average of $2-3 billion per annum on an ongoing basis.

We intend to target our net debt ratio within the 10-20% range while uncertainties remain. Net debt is a non-GAAP measure.

Depreciation, depletion and amortization in 2013 is expected to be around $0.5-1.0 billion higher than in 2012.

For 2013, the underlying effective tax rate (ETR) (which excludes non-operating items and fair value accounting effects) is expected to be in the range of 36-38% compared with 30% in 2012. The increase in the forecast rate is mainly due to a lower level of equity-accounted income in 2013, which is reported net of tax in the income statement.

Forward-looking statements

The discussion above contains forward-looking statements, particularly those regarding production in Upstream, the expected financial impact of refinery turnarounds, expectations regarding petrochemicals margins and the average quarterly charge for Other businesses and corporate, estimated levels of capital expenditure in 2013 and to the end of the decade, estimated amount of divestments, intentions regarding net debt ratio and the expected level of depreciation, depletion and amortization, and the expected level of underlying ETR. 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 should not rely on past performance as an indicator of future performance. You are urged to read the cautionary statement on page 32 and Risk factors on pages 38-44, 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.

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 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 BP's 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 owned or controlled 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), although arrangements with the US government can be by lease. 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-owned or controlled 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 only a portion of the area covered by the original exploration licence. Both exploration and production licences are generally for a specified period of time. In the US, leases from the US government typically remain in effect for a specified term, but may be extended beyond that term as long as there is production in paying quantities. The term of BP's licences and the extent to which these licences may be renewed vary from country to country.

Frequently, BP conducts its exploration and production activities in joint ventures or co-ownership arrangements with other international oil companies, state-owned or controlled companies and/or private companies. These joint ventures may be incorporated or unincorporated ventures, while the co-ownerships are typically unincorporated. Whether incorporated or unincorporated, relevant agreements set out each party's level of participation or ownership interest in the joint venture or co-ownership. Conventionally, all costs, benefits, rights, obligations, liabilities and risks incurred in carrying out joint-venture or co-ownership operations under a lease or licence are shared among the joint-venture or co-owning parties according to these agreed ownership interests. Ownership of joint-venture or co-owned property and hydrocarbons to which the joint venture or co-ownership is entitled is also shared in these proportions. To the extent that any liabilities arise, whether to governments or third parties, or as between the joint venture parties or co-owners themselves, each joint venture party or co-owner will generally be liable to meet these in proportion to its ownership interest (see Financial statements – Note 2 on page 194 in relation to the Gulf of Mexico oil spill). In many upstream operations, a party (known as the operator) will be appointed (pursuant to a joint operating agreement (JOA)) to carry out day-to-day operations on behalf of the joint venture or co-ownership. The operator is typically one of the joint venture parties or a co-owner and will carry out its duties either through its own staff, or by contracting out various elements to third-party contractors or service providers. BP acts as operator on behalf of joint ventures and co-ownerships in a number of countries where we have exploration and production activities.

Frequently, work (including drilling and related activities) will be contracted out to third-party service providers who have the relevant expertise and equipment not available within the joint venture or the co-owning operator's organization. The relevant contract will specify the work to be done and the remuneration to be paid and typically will set out how major risks will be allocated between the joint venture or co-ownership and the service provider. Generally, the joint venture or co-owner and the contractor would respectively allocate responsibility for and provide reciprocal indemnities to each other for harm caused to their respective staff and property. Depending on the service to be provided, an oil and gas industry service contract may also contain provisions allocating risks and liabilities associated with pollution and environmental damage, damage to a well or hydrocarbon reservoir and for claims from third parties or other losses. The allocation of those risks vary among contracts and are determined through negotiation between the parties.

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, for example in Abu Dhabi, Angola, Egypt, Norway, the UK, the US, Russia and Trinidad & Tobago.

Environmental regulation

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

There are also environmental laws that require BP to remediate and restore areas affected by the release of hazardous substances or hydrocarbons 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 36 on page 235 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 or other sanctions. We are also subject to environmental claims for personal injury and property damage alleging the release of 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. 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 53.

A significant proportion of our fixed assets are located in the US and the EU. US and EU environmental, health and safety regulations significantly affect BP's exploration and production, refining and marketing, transportation and shipping operations. Significant legislation and regulation 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 in future, as will actions on greenhouse gas (GHG) emissions and other air pollutants. Additionally, states may have separate, stricter air emission laws in addition 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 mandates and imposing GHG emissions thresholds for certain renewable fuels. States such as California also impose additional fuel carbon standards.
- The Clean Water Act 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 regulates the generation, storage, transportation and disposal of wastes associated with our operations and can require corrective action at locations where such wastes have been 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 site contaminated with a hazardous substance, or arranged for disposal of a hazardous substance at the site. BP has incurred, or expects to incur, liability under the 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 under the CERCLA, the Oil Pollution Act of 1990 (OPA 90) (discussed below) and other federal and state laws. CERCLA also requires hazardous substance release notification.
- The Toxic Substances Control Act regulates BP's import, export and sale of new chemical products.
- The Occupational Safety and Health Act imposes workplace safety and health requirements on BP 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, petrochemicals and other hydrocarbon liquids.
- The Marine Transportation Security Act (MTSA), the DOT Hazardous Materials (HAZMAT) and the Chemical Facility Anti-Terrorism Standard (CFATS) regulations impose security compliance regulations on around 50 BP facilities. These regulations require security vulnerability assessments, security risk mitigation plans and security upgrades, increasing our cost of operations.

OPA 90 is implemented through regulations issued by the US Environmental Protection Agency (EPA), the US Coast Guard, the DOT, the Occupational Safety and Health Administration and various states. Alaska and the west coast states currently have the most demanding state requirements although regulation in the Gulf of Mexico has increased following the 2010 Deepwater Horizon incident. There is an expectation that OPA 90 and its regulations will become more stringent in the future. The impact will likely be more rigorous preparedness requirements (the ability to respond over a longer period to larger spills), including the demonstration of that preparedness. There are expected to be additional costs associated with this increased regulation. In 2013, we expect more unannounced exercises and potential penalties for any failure to demonstrate required preparedness even without any OPA 90 amendments.

As a consequence of the Deepwater Horizon incident BP has become subject to claims under OPA 90 and other laws and have established a $20-billion trust fund for legitimate state and local government response claims, final judgments and settlement claims, legitimate state and local response costs, natural resource damages and related costs and legitimate individual and business claims. We are also subject to Natural Resource Damages claims and numerous civil lawsuits by individuals, corporations and governmental entities. The ultimate costs for these claims cannot be determined at this time. We also expect the industry in general, and BP in particular, to become subject to greater regulation and increased operating costs in the Gulf of Mexico in the future. For further disclosures relating to the consequences of the 2010 Deepwater Horizon oil spill, see Legal proceedings on pages 162-169.

BP is in settlement discussions with EPA to resolve alleged CAA violations at the Toledo, Carson and Cherry Point refineries.

European Union

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

- The 2008 EU Climate and Energy Package, including the EU Emissions Trading System (EUETS) Directive and the Renewable Energy Directive (see Greenhouse gas regulation on page 52). In 2013, the European Commission is expected to propose a new Climate and Energy Package for the period up to 2030.
- Under the third trading period – 'Phase III' – which started on 1 January 2013, the EUETS has been expanded to include the petrochemical sector, free allocation is via sector benchmarking, and auctioning is the default method for allocating allowances to some sectors including electricity generation and production, though sectors at risk of carbon leakage are partially compensated with free allocation.
- The Energy Efficiency Directive (EED) was adopted in 2012. It requires EU Member states to implement an indicative 2020 energy saving target and apply a framework of measures as part of a national EED programme. Such measures include mandatory industrial energy efficiency surveys, and providing data on new and replacement of large plants. Such a programme may result in requirements to implement additional energy saving measures at BP's sites and/or higher power prices for BP's operations.
- The EU Industrial Emissions Directive (IED) (revising and replacing the Integrated Pollution Prevention and Control Directive (IPPC)) and several other industrial directives including the Large Combustion Plant Directive (LCPD) should be transposed into national law by the EU Member states by 7 January 2013. The IED provides the framework for setting permits for major industrial sites. Relative to IPPC and LCPD, the IED imposes tighter emission standards for some large combustion plants and is more prescriptive regarding the setting of emission of limit values based on use of Best Available Techniques (BAT) in permits for other discharges to air and water. The emission limit values are informed by the sector specific and cross-sector BAT Reference documents (BREFs), which are reviewed periodically. The outcome of the review of several BREFs relevant to our major sites is expected in 2013. The IED transposition and output from the BREF revisions may result in requirements for further emission reductions at our EU sites. The LCPD imposes air quality standards requiring retrofit of flue gas desulphurization equipment, particularly for coal-fired power stations, that may force some of them to close. This is expected to impact the relative demand for natural gas and electricity prices.
- The European Commission Thematic Strategy on Air Pollution and the related work on revisions to the Gothenburg Protocol and National Emissions Ceiling Directive (NECD) will establish national ceilings for emissions of a variety of air pollutants in order to achieve EU-wide health and environmental improvement targets. This may result in requirements for further emission reductions at BP's EU sites.
- The implementation of the Water Framework Directive and the Environmental Quality Directive are likely to require BP to take further steps to manage water discharges from its refineries and chemical plants in the EU.
- The EU Regulation on ozone depleting substances (ODS), which implements the Montreal Protocol (Protocol) on ODS was most recently revised in 2009. It requires BP to reduce the use of ODS and phase out use of 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 by-product in the production of purified terephthalic acid in our petrochemicals operations. The progressive phase-out of

methyl bromide uses may result in future pressure to reduce our emissions of methyl bromide. In addition, the European Commission recently proposed a revised regulation to phase out the use of fluorinated gases, including hydrofluorocarbons (HFCs). While targeting all HFCs, there is specific emphasis on those with a high global-warming potential. If adopted, this may have an impact on some of BP's operations.

- The EU Fuel Quality Directive affects our production and marketing of transport fuels. Revisions adopted in 2009 mandate reductions in the life cycle GHG emissions per unit of energy and tighter environmental fuel quality standards for petrol and diesel.

The EU Registration, Evaluation and Authorization of Chemicals (REACH) Regulation requires registration of chemical substances, manufactured in, or imported into, the EU in quantities greater than 1 tonne per annum per legal entity, together with the submission of relevant hazard and risk data. REACH affects our refining, petrochemicals, exploration and production, biofuels, lubricants and other manufacturing or trading/import operations. Having completed registration of all the substances that we were required to submit by the regulatory deadline of 1 December 2010, we are now preparing registration dossiers for substances manufactured or imported in amounts in the range 100-1,000 tonnes per annum/legal entity that are due to be submitted before 1 June 2013. Some substances registered previously in 2010, including substances that we use that are supplied to us by third parties, are now subject to thorough evaluation and/or potential authorization/restriction procedures by the European Chemicals Agency and EU Member state authorities. Legislation similar to REACH is in place in Turkey, which requires the registration of manufactured and imported chemicals.

- In addition, Europe has adopted the UN Global Harmonization System for hazard classification and labelling of chemicals and products through the Classification Labelling and Packaging (CLP) Regulation. This requires BP to assess the hazards of all of our chemicals and products against new criteria and will, over time, result in significant changes to warning labels and material safety data sheets. All our European Material Safety Data Sheets will need to be updated to include both REACH and CLP information. We have already completed updates for all chemical substances we manufacture and market in the EU by the compliance deadline in 2011, and have implemented a process to maintain compliance in our European operations. We have also notified the European Chemicals Agency of hazard classifications for our manufactured and imported chemicals, for inclusion in a publicly available inventory of hazardous chemicals. CLP will also apply to mixtures (e.g. lubricants) by 2015. Activities covered by both CLP and REACH are subject to possible enforcement activity by national regulatory authorities.
- 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.

The EU Commission has proposed the adoption of a regulation on safety of offshore oil and gas prospection, exploration and production activities. While the proposal at this stage is likely to be adopted in the form of a directive rather than a regulation, it aims to introduce a harmonized regime aimed at reducing the potential environmental, health and safety impacts of the offshore oil and gas industry throughout EU waters. Although the legislative process is not complete, as proposed, the legislation would not be entirely aligned with the regime currently operating in the UK and could also, if adopted, have the effect of extending liability for clean-up and compensation of environmental damage to marine waters.

Environmental maritime regulations

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

- In US waters, OPA 90 imposes liability and spill prevention and planning requirements governing, among others, tankers, barges and offshore facilities. It also mandates a levy on imported and domestically produced oil to fund the 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 MARPOL Convention, the International Convention on Oil Pollution, Preparedness, Response and Co-operation and the International Convention on Civil Liability for Bunker Oil Pollution Damage. In April 2010, a new protocol, the Hazardous and Noxious Substance (HNS) Protocol 2010, was adopted to address issues that have inhibited ratification of the International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea 1996 (the HNS Convention). This protocol will enter into force when at least 12 states have agreed to be bound by it (four of the states must have at least 2 million gross tonnes of shipping) and contributing parties in the consenting states have received at least 40 million tonnes of contributing cargoes in the preceding year. As at 3 January 2013, 14 states had signed or acceded to the Convention subject to ratification but it had not yet entered into force.
- In April 2008, the International Maritime Organization approved amendments to Annex VI of The International Convention for the Prevention of Pollution from Ships (MARPOL) to reduce the sulphur content in marine fuels. With effect from 1 January 2012 the global limit of sulphur content in marine fuels was reduced and now shall not exceed 3.50%. This global limit will be further reduced to 0.5% in 2020, provided there is enough fuel available. Annex VI also provides for stricter sulphur emission restrictions on ships in SOx Emission Control Areas (SECAs). EU ports and inland waterways and the North Sea and Baltic Sea have been covered by SECAs since 2010 imposing a sulphur content limit of 0.1%. These restrictions require the use of compliant heavy fuel oil (HFO) or distillate, or the installation of abatement technologies on ships. These restrictions are expected to place additional costs on refineries producing marine fuel, including costs to dispose of sulphur, as well as increased GHG emissions and energy costs for additional refining.

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.

Greenhouse gas regulation

Increasing concerns about climate change have led to a number of international climate agreements and negotiations are ongoing.

At the UN summit in Cancun in December 2010, the parties to the UN Framework Convention on Climate Change (UNFCCC) reached formal agreement on a balanced package of measures to 2020. The Cancun Agreement recognizes that deep cuts in global GHG emissions are required to hold the increase in global temperature to below 2°C. Signatories formally committed to carbon reduction targets or actions by 2020. Around 114 countries, including all the major economies and many developing countries, have made such commitments supplemented currently by an additional 27 parties that have agreed to be listed as agreeing to the accord. Supporting those efforts, principles were agreed for monitoring, verifying and reporting emissions reductions; establishment of a green fund to help developing countries limit and adapt to climate change; and measures to protect forests and transfer low-carbon technology to poorer nations. In November 2011, parties to the UNFCCC conference in Durban (COP17) agreed several measures. One was a 'roadmap' for negotiating a legal framework by 2015 for action on climate change involving all countries by 2020, to close the 'ambition gap' between existing GHG reduction pledges and what is required to achieve the goal of limiting global temperature rise to 2°C. Another was a second commitment period for the Kyoto Protocol, to begin immediately after the first period. An amendment was subsequently adopted at the 2012 conference of parties (COP18) in Doha establishing a second commitment period to run until the end of 2020. However, it will not include the US, Canada, Japan and Russia, thus covers only about 15% of global emissions.

Aspects of these international concerns and agreements are reflected in national and regional measures seeking to limit GHG emissions. Additional, more stringent, measures can be expected in the future. These measures can increase BP's production costs for certain products, increase demand for competing energy alternatives or products with lower-carbon intensity and affect the sales and specifications of many of BP's products. Current measures and developments potentially affecting BP's businesses include the following:

- The European Union (EU) has agreed an overall GHG reduction target of 20% by 2020. To meet this, a 'Climate and Energy Package' of regulatory measures has been adopted including: national reduction targets for emissions not covered by the EUETS; binding national renewable energy targets to double renewable energy in the EU including at least a 10% share of final energy in transport; a legal framework to promote carbon capture and storage (CCS); and a revised EUETS Phase 3. EUETS revisions include a GHG reduction of 21% from 2005 levels, a significant increase in allowance auctioning, an expanded scope (sectors and gases), no free allocations for electricity production but free allocations for energy-intense and trade-exposed industrial sectors. Finally, EU energy efficiency policy is currently addressed via national energy efficiency action plans and the Energy Efficiency Directive adopted in 2012.
- Article 7a of the revised EU Fuel Quality Directive requires fuel suppliers to reduce the life cycle GHG emissions per unit of fuel and energy supplied in certain transport markets.
- Australia has committed to reduce its GHG emissions by at least 5% below 2000 levels by 2020. In support of this, a Clean Energy legislative package of 19 bills was passed in November 2011, which includes imposing a carbon price on the top 500 emitting entities meeting the thresholds in the bill. The carbon price took effect on 1 July 2012 with a fixed price of $23 Australian dollars (indexed to forecast inflation) until 1 July 2015, an international linked price (trading) with floor and ceiling prices from 1 July 2015 through to 1 July 2018, and a market-based price (trading) forward. A certain portion of allowances will be distributed to 'emission intensive trade exposed' businesses for no cost; this transitional support decreases with time. The majority of our Australia business emissions will be subject to the pricing scheme and will require additional expenditures for compliance.
- New Zealand has agreed to cut GHG emissions by 10-20% below 1990 levels by 2020, subject to a comprehensive global agreement for emissions reductions coming into force. New Zealand's emission trading scheme (NZ ETS) commenced on 1 July 2010 for transport fuels, industrial processes and stationary energy. New Zealand also employs a portfolio of mandatory and voluntary complementary measures aimed at GHG reductions. New Zealand has announced its intention to make its next commitments for GHG reduction under the UN Framework Convention rather than the Kyoto treaty.
- In the US, with the potential for passing comprehensive climate legislation remaining very unlikely, the US Environmental Protection Agency (EPA) continues to pursue regulatory measures to address GHGs under the Clean Air Act (CAA).
  - In late 2009, the EPA released a GHG endangerment finding to establish its authority to regulate GHG emissions under the CAA.
  - Subsequent to this, the EPA finalized regulations imposing light duty vehicle emissions standards for GHGs.
  - The EPA finalized the initial GHG mandatory reporting rule (GHGMRR) in 2009 and continues to make amendments to the rule. Reports under the GHGMRR are due annually. The majority of BP's US businesses are affected by the GHGMRR and submitted their GHG emissions reports to the EPA under the GHGMRR on or before the required deadlines. In addition to direct emissions from affected facilities, producers and importers/exporters of petroleum products, certain natural gas liquids and GHGs are required to report product volumes and notional GHG emissions as if these products were fully combusted. The EPA is expected to publically release direct and product emission early in 2013 with certain confidential business information protections.
  - The EPA finalized permitting requirements for new or modified large GHG emission sources in 2010, with these regulations taking effect in January 2011, the second phase taking effect on 1 July 2011 and the third phase finalized on 29 June 2012.
  - In a legal settlement with environmental advocacy groups the EPA committed to propose regulations under their New Source Performance Standards (NSPS) for GHG emissions from refineries by December 2011 and to finalize these by November 2012. These deadlines were not met and it is not known when or if EPA will propose regulations for refineries under their NSPS provisions.
  - Legal challenges to the EPA's efforts to regulate GHG emissions through the CAA continue along with active political debate with the final content and scope of GHG regulation in the US remaining uncertain.
- A number of additional state and regional initiatives in the US will affect our operations. Of particular significance, California is seeking to reduce GHG emissions to 1990 levels by 2020 and to reduce the carbon intensity of transport fuel sold in the state, California implemented a low-carbon fuel standard in 2010. Although legal challenges continue, the preliminary injunction stopping implementation was lifted and implementation of the programme continues. The California cap and trade programme started in January 2012 with the first auctions of carbon allowances held in November 2012 and obligations commencing in 2013.
- Canada has established an action plan to reduce emissions to 17% below 2005 levels by 2020 and the national government continues to seek a co-ordinated approach with the US on environmental and energy objectives. Additionally, Canada's highest emitting province, Alberta, has been running a market mechanism to reduce GHG since 2007. Controversy, partially driven by perceived GHG intensity regarding Canadian oil sand produced crude, continues with some jurisdictions contemplating policies to restrict or penalize its use.
- China has committed to reducing carbon intensity of GDP 40-45% below 2005 levels by 2020 and increasing the share of non-fossil fuels in total energy consumption from 7.5% in 2005 to 15% by 2020. The country's 12th (2011-2015) Development Programme has set the target to reduce carbon intensity by 17% within five years, and this national target has been deconstructed into provincial ones for local actions. Meanwhile, two provinces and five cities are developing pilot schemes for emissions trading. As part of the country's energy saving programme, the government also requires any operating entity with annual energy consumption of 10 thousand tonnes of coal equivalent (7ktoe/a) to have an energy saving target for the next five years. A number of BP joint venture companies in China will be required to participate in these initiatives.

Certain definitions

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

Replacement cost profit

Replacement cost (RC) profit or loss reflects the replacement cost of supplies and is arrived at by excluding inventory holding gains and losses from profit or loss. 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, both RC profit or loss before interest and tax and underlying RC profit or loss before interest and tax are provided regularly to the chief operating decision maker. In such cases IFRS requires that the measure of profit disclosed for each operating segment is the measure that is closest to IFRS, which for BP is RC profit or loss before interest and tax. RC profit or loss for the group is not a recognized GAAP measure. The nearest equivalent GAAP measure is profit or loss for the year attributable to BP shareholders. BP believes that replacement cost profit before interest and taxation for the group is a useful measure for investors because it is a profitability measure used by management. A reconciliation is provided between the total of the operating segments' measures of profit or loss and the group profit or loss before taxation, as required under IFRS. See Financial statements – Note 6 on page 203.

Inventory holding gains and losses

Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies acquired during the period and the cost of sales calculated on the first-in first-out (FIFO) method after adjusting for 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 its historic cost of purchase, or manufacture, rather than its 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) for inventory on a FIFO basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen if an average cost of supplies was used for the period. For this purpose, the average cost of supplies during the period is principally calculated on a monthly basis by dividing the total cost of inventory acquired 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.

Underlying replacement cost profit

Underlying RC profit or loss is RC profit or loss after adjusting for non-operating items and fair value accounting effects. Underlying RC profit or loss and fair value accounting effects are not recognized GAAP measures. On page 37 we provide additional information on the non-operating items and fair value accounting effects that are used to arrive at underlying RC profit or loss in order to enable a full understanding of the events and their financial impact.

BP believes that underlying RC profit or loss before interest and taxation is a useful measure for investors because it is a measure closely tracked by management to evaluate BP's operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in BP's operational performance on a comparable basis, year on year, by adjusting for the effects of these non-operating items and fair value accounting effects. The nearest equivalent measure on an IFRS basis for the group is profit or loss for the year attributable to BP shareholders. The nearest equivalent measure on an IFRS basis for segments is RC profit or loss before interest and taxation.

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. Under IFRS, these inventories are recorded at historic cost. 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 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.

BP enters into commodity contracts to meet certain business requirements, such as the purchase of crude for a refinery or the sale of BP's gas production. Under IFRS these contracts are treated as derivatives and are required to be fair valued when they are managed as part of a larger portfolio of similar transactions. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

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, oil and gas processing and liquefied natural gas (LNG) 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 management's internal measure of performance the inventory, capacity, oil and gas processing and LNG contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period and the commodity contracts for business requirements are accounted for on an accruals basis. 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 and a reconciliation to GAAP information is shown on page 37.

Commodity trading contracts

BP's Upstream and Downstream segments both participate in regional and global commodity trading markets in order to manage, transact and hedge the crude oil, refined products and natural gas that the group either produces or consumes in its manufacturing operations. These physical trading activities, together with associated incremental trading opportunities, are discussed further in Upstream on page 71 and in Downstream on page 77. The range of contracts the group enters into in its commodity trading operations is as follows.

Exchange-traded commodity derivatives

These contracts are typically in the form of futures and options traded on a recognized exchange, such as Nymex, SGX and ICE. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate, the main product grades, such as gasoline and gasoil, and for natural gas and power. 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 crude oil, refined products, natural gas and power. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

Over-the-counter 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 for trading and risk management activities. Realized and unrealized gains and losses on over-the-counter (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 Oseberg or BFO). Although the contracts specify physical delivery terms for each crude blend, a significant number 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.

Gas and power OTC markets are highly developed in North America and the UK, where the commodities 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, which 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 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, oil products, natural gas or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry. Typically, netting agreements are used to limit credit exposure and support liquidity.

Spot and term contracts
Spot contracts are contracts to purchase or sell a commodity at the market price prevailing on 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 typically relate to purchases of crude for a refinery, purchases of products for marketing, purchases of third-party natural gas, sales of the group's oil production, sales of the group's oil products 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.

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.

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.

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.

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.

Corporate governance

Information on how the company is governed, including risk management and activities of the board.

Directors' remuneration report
For more information see page 127.

Regulatory information
For more information see page 147.

Governance overview

> “Your board has three goals for BP: to operate safely, to earn people’s trust, and to create sustainable value for shareholders.”

In my letter to shareholders at the front of this report, I stated that the BP board is well balanced, with a broad range of skills and deep experience in our industry. The governance report which follows describes the work of this board and its committees over the past year. Here I give my own view of the journey that the BP board has taken from April 2010 to the present day.

Board evolution

In this period, the board has seen substantial change amongst both the executive and non-executive directors. Eight out of the eleven non-executives have served four years or less. The intense work undertaken from 2010 has unified and strengthened the board. The team has stuck resolutely to its tasks, and has worked together effectively to address a number of tough challenges.

Board goals

The board has three goals for BP: to operate safely, to earn people’s trust, and to create sustainable value for shareholders. The pursuit of these goals has been the foundation of our work and will continue to be so for years to come.

For some time the board has governed within a clear set of robust principles and believes that good governance involves the clarity of roles and responsibilities and the utilization of distinct skills and processes. This has enabled us to carry out the fundamental tasks of strategy development and performance monitoring and oversight, while also responding to the challenges which arose from the Gulf of Mexico accident and wider business events.

We evaluate our performance and effectiveness as a board each year. But we continue to review and improve what we are doing, and how we are doing it, as we move forward. It is important that the board evolves so it can best support the company as it changes. Our work during the year to support the fundamental reorganization of the company is one example of this approach in action.

Inevitably, much of our work is focused on determining the company’s approach to risk. Over the past three years we have reviewed our governance and management of risk, and we have monitored and assessed the group’s evolution of its systems. One of the key tasks of the board is to review particular group-level risks; this review forms the basis of the board’s annual forward agenda.

Board committees

The Gulf of Mexico committee, formed in August 2010, has done much of the heavy lifting in terms of the board’s oversight of the Gulf response and litigation. The work of this committee has been intense but invaluable in drawing together the many strands of activity in the US. This has enabled the board to focus on its other roles, including strategy and oversight of the group’s operations.

When the board decided to pursue the sale of BP’s interest in TNK-BP, it was clear that this would be a complex and concentrated process. Based on the successful experience with the Gulf of Mexico committee, we formed an ad hoc committee to advise and have oversight of the work of executive management during the transaction. Antony Burgmans, our longest serving non-executive director, chaired this committee. The committee has proved its value in terms of monitoring and consultation. The transaction is due to complete in the first half of 2013.

Board meetings and board skills

Our governance processes are designed to ensure that the board can carry out all of its tasks effectively. Pressing matters have inevitably taken an increased proportion of the board’s time over the past three years. We have met much more often than we would normally. Events have meant that our meetings have sometimes had to take place at short notice. The attendance at these meetings is a reflection of the very strong commitment of the directors to your company. The response of all the directors has been excellent.

I believe the board is benefiting significantly from the balance of skills and experience that I mentioned earlier. Here is an outline of the main areas of expertise of our current board:

Director	Key skills and experience
Paul Anderson	Oil and gas industry experience
Admiral Frank Bowman	Safety, technology and risk management
Antony Burgmans	Food and consumer goods; leading a global business
Cynthia Carroll	Oil, gas and extractive industry experience; leading a global business
Carl-Henric Svanberg	Manufacturing and telecoms; leading a global business
George David	Technology and manufacturing
Ian Davis	Strategy, advisory and consulting
Brendan Nelson	Audit, financial services and trading
Phuthuma Nhleko	Civil engineering, telecoms and banking
Andrew Shilston	Oil and gas industry experience; finance
Professor Dame Ann Dowling	Engineering, technology and education

Board support

BP is a global company and there are many challenges for the board to address. One of the features of our system of governance is the independent advice and support that the board receives from our company secretarial team. Each committee has a dedicated secretary, and this has assisted greatly in the organization of work.

During the year BP has benefited from the insight and expertise of our international advisory board – a group of distinguished individuals with deep knowledge of geopolitical issues and whose counsel has been invaluable.

Looking forward

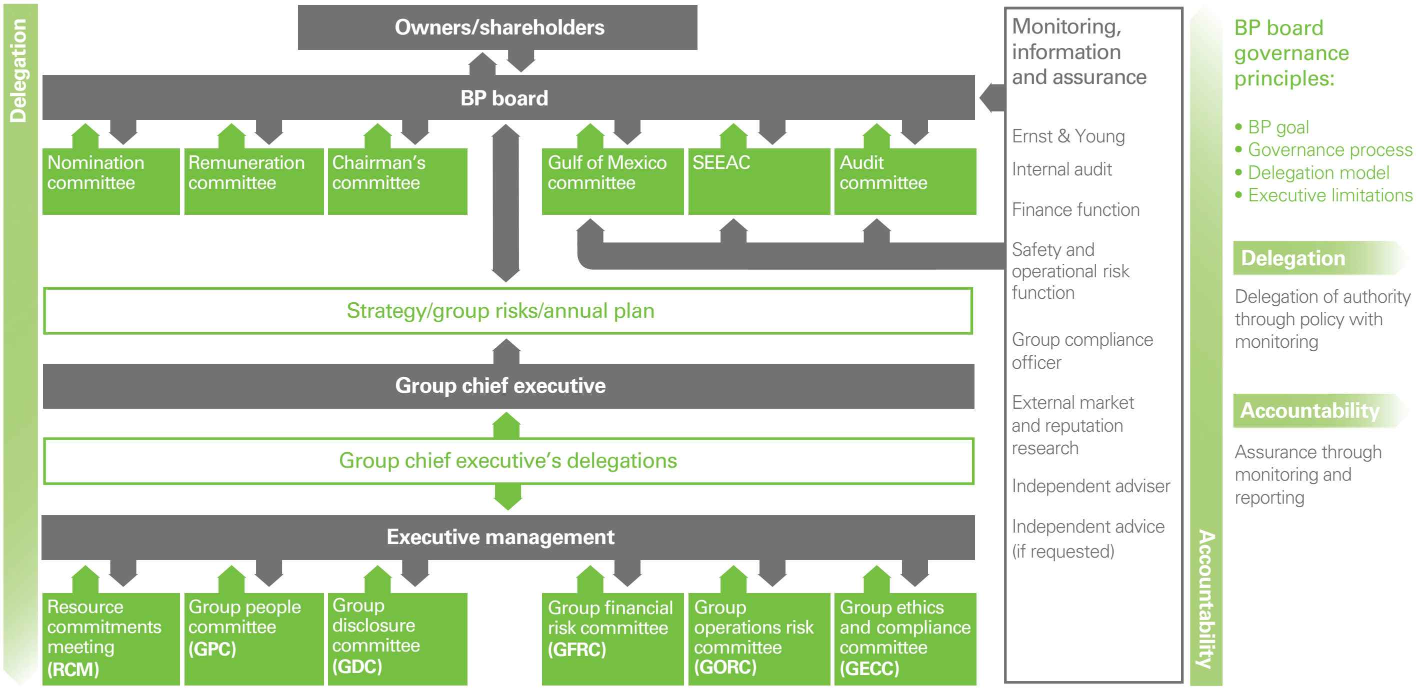
2012 was a year of progress for BP. Some uncertainties remain, but there is a clear direction towards 2014 and beyond. We have a strong team around the board table. We understand the challenges we face. And we are clear that the company must continue to make good progress on achieving its three goals, not least sustainable value for our shareholders. Finally, I would like to take this opportunity to thank my fellow board members for all that they have done in the year.

Carl-Henric Svanberg
Chairman

International advisory board

- → In 2009, BP formed an international advisory board (IAB) whose purpose is to advise the chairman, group chief executive and the board on geopolitical and strategic issues relating to the company.
- → This group has an advisory role and meets twice a year – although its members are on hand to provide advice and counsel to the company when needed.
- → The IAB is chaired by BP's previous chairman, Peter Sutherland.
- → Its membership in 2012 included Kofi Annan, Lord Patten of Barnes, Josh Bolten, President Romano Prodi, Dr Ernesto Zedillo and Dr Javier Solana.
- → The chairman and chief executive attend meetings of the IAB.
- → Issues discussed during the year included events in the Middle East, the eurozone crisis, Russia and the US presidential election.

BP governance framework



Board of directors

As at 6 March 2013

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1 Carl-Henric Svanberg
2 Bob Dudley
3 Iain Conn
4 Dr Brian Gilvary
5 Dr Byron Grote
6 Paul Anderson
7 Admiral Frank Bowman
8 Antony Burgmans KBE
9 Cynthia Carroll
10 George David
11 Ian Davis
12 Professor Dame Ann Dowling
13 Brendan Nelson
14 Phuthuma Nhleko
15 Andrew Shilston

Board of directors

Carl-Henric Svanberg

Current position

Carl-Henric Svanberg is BP's chairman. He was appointed a non-executive director of BP on 1 September 2009 and became chairman on 1 January 2010.

Board and committee activities

He chairs the chairman's and the nomination committees and attends the Gulf of Mexico and the remuneration committees.

Outside interests

Carl-Henric Svanberg is chairman of AB Volvo.

Career

He spent his early career at Asea Brown Boveri and the Securitas Group, before moving to the Assa Abloy Group as president and chief executive officer.

From 2003 until 31 December 2009, when he left to join BP, he was president and chief executive officer of Ericsson, also serving as the chairman of Sony Ericsson Mobile Communications AB. He was a non-executive director of Ericsson between 2009 and 2012. He was appointed chairman and a member of the board of AB Volvo on 4 April 2012.

He is a member of the External Advisory Board of the Earth Institute at Columbia University and a member of the Advisory Board of Harvard Kennedy School.

Relevant experience and skills

Carl-Henric Svanberg's career in international business, latterly as chief executive officer of Ericsson, is particularly relevant to BP globally. During the year, in addition to leading the board, he has contributed to the work of the Gulf of Mexico and the remuneration committees and has chaired the nomination committee. He has focused on succession within the executive team and amongst the non-executive directors. He has developed a well-balanced board that has contributed to BP's strategy and delivery of shareholder value.

Bob Dudley

Current position and group responsibilities

Bob Dudley is BP's group chief executive. He was appointed an executive director of BP on 6 April 2009.

Outside interests

Bob Dudley has no external appointments.

Career

He joined Amoco Corporation in 1979, working in a variety of engineering and commercial posts. Between 1994 and 1997, he worked on corporate development in Russia. In 1997, he became general manager for strategy for Amoco and in 1999, following the merger between BP and Amoco, was appointed to a similar role in BP.

Between 1999 and 2000, he was executive assistant to the group chief executive, subsequently becoming group vice president for BP's Renewables and Alternative Energy activities. In 2002, he became group vice president responsible for BP's upstream businesses in Russia, the Caspian region, Angola, Algeria and Egypt.

From 2003 to 2008, he was president and chief executive officer of TNK-BP.

On his return to BP in 2009 he was appointed to the BP board and oversaw the group's activities in the Americas and Asia. Between 23 June and 30 September 2010, he served as the president and chief executive officer of BP's Gulf Coast Restoration Organization in the US. He became group chief executive on 1 October 2010.

Relevant experience and skills

Bob Dudley has spent his entire career in the oil and gas industry. His broad range of roles with Amoco and BP have given him substantial global experience. This has been supplemented by his time as chief executive officer of TNK-BP. He has performed strongly as BP's chief executive officer since his appointment in 2010.

Paul Anderson

Current position

Paul Anderson was appointed a non-executive director of BP on 1 February 2010.

Board and committee activities

He is chairman of the safety, ethics and environment assurance committee (SEEAC) and is a member of the chairman's, the Gulf of Mexico and the nomination committees.

Outside interests

Paul Anderson is a non-executive director of BAE Systems PLC.

Career

He was formerly chief executive at BHP Billiton and Duke Energy, where he also served as chairman of the board. 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 two boards in 2006 as a non-executive director, retiring on 31 January 2010. Previously he served as a non-executive director on a number of boards in the US and Australia and as chief executive officer of Pan Energy Corp.

Relevant experience and skills

Paul Anderson took the chair of the SEEAC in December 2012. As chair he has continued the committee's focus on safety matters both in meetings and through visits to the company's operations. His broad experience of the global oil and gas industry and of the US business environment has benefited both the board, the SEEAC and the Gulf of Mexico committee. He has actively supported the work of the BP Massachusetts Institute of Technology (MIT) academy. This global perspective has also enabled him to guide the work of the ad-hoc Russia committee.

Admiral Frank Bowman

Current position

Frank Bowman was appointed a non-executive director of BP on 8 November 2010.

Board and committee activities

He is a member of the SEEAC and the chairman's and the Gulf of Mexico committees.

Outside interests

Frank Bowman is president of Strategic Decisions, LLC and a director of Morgan Stanley Mutual Funds, the American Shipbuilding Suppliers Association, and the Naval and Nuclear Technologies, LLP.

Career

He joined the United States Navy in 1966. During his naval service, he commanded the nuclear submarine *USS City of Corpus Christi* and the *USS Holland*. He served as a flag officer; as the Navy's chief of personnel; on the joint staff as director of Political-Military Affairs; and as director of the naval nuclear propulsion programme in the Department of the Navy and the Department of Energy for over eight years.

After his retirement as an Admiral in 2004, he was president and chief executive officer of the Nuclear Energy Institute until 2008. He served on the BP Independent Safety Review Panel and was a member of the BP America External Advisory Council. He was appointed Honorary Knight Commander of the British Empire in 2005 by Queen Elizabeth II. He was also elected to the US National Academy of Engineering in 2009.

Relevant experience and skills

Frank Bowman has a deep knowledge of engineering coupled with exceptional experience in safety arising from his time with the US Navy and, later, the Nuclear Energy Institute. His service on the BP Independent Safety Review Panel gave him direct experience of BP's safety aims and requirements, particularly in the area of refining. He makes a significant contribution to the work of the SEEAC and the Gulf of Mexico committee. He has actively supported the work of the BP MIT academy.

Antony Burgmans KBE

Current position

Antony Burgmans was appointed a non-executive director of BP on 5 February 2004.

Board and committee activities

He is chairman of the remuneration committee and is a member of the SEEAC and the chairman's and the nomination committees.

Outside interests

Antony Burgmans is a member of the supervisory boards of Akzo Nobel N.V., AEGON N.V. and SHV Holdings N.V., and chairman of the supervisory board of TNT Express.

Career

He joined Unilever in 1972, holding a succession of marketing and sales posts, including, from 1988 until 1991, the chairmanship of PT Unilever Indonesia.

In 1991, he was appointed to the board of Unilever, becoming business group president, ice cream and frozen foods, Europe in 1994, and chairman of Unilever's Europe committee, co-ordinating its European activities. In 1998, he became vice chairman of Unilever NV and in 1999, chairman of Unilever NV and vice chairman of Unilever PLC. In 2005, he became non-executive chairman of Unilever NV and Unilever PLC until his retirement in 2007.

Relevant experience and skills

Antony Burgmans' executive career was in international production, distribution and marketing. Over the years he has made a significant contribution to the work of the board, adding insight to the areas of reputation, brand and culture. His global perspective has particular value as chairman of the remuneration committee and also contributes to his work on the SEEAC. During the year he has led on internal board matters in support of the senior independent director. His tenure and independent approach, demonstrated over many years in his work on SEEAC and the nomination and remuneration committees, led the board to ask him to chair the ad-hoc committee of the board dealing with issues relating to the sale of BP's share in TNK-BP. His clarity of thought and his approach in evaluating the events of the last few years has led the board to conclude that he is still independent even though he has now served just over nine years as a director. His continued independence, together with his experience of the BP board and the need for an orderly board succession, means that the board has asked him to remain as a member of the BP board for a further period of three years.

Cynthia Carroll

Current position

Cynthia Carroll was appointed a non-executive director of BP on 6 June 2007.

Board and committee activities

She is a member of the SEEAC and the chairman's and the nomination committees.

Outside interests

Cynthia Carroll is currently chief executive of Anglo American plc, the global mining group, chairman of Anglo Platinum Limited and chairman of De Beers s.a. She will relinquish these roles on 3 April 2013 and will step down as a director of Anglo American, Anglo Platinum and De Beers at Anglo American's AGM in April 2013.

Career

She started her career with Amoco as a petroleum geologist in oil exploration. In 1989, she joined Alcan Inc, where she spent 18 years before joining Anglo American in January 2007. Starting in the business development group of the Rolled Products Division in Alcan, she became president and chief executive officer of the Primary Metal Group, responsible for operations in more than 20 countries. She has been chief executive of Anglo American plc since March 2007.

Relevant experience and skills

Cynthia Carroll's leadership of global businesses, particularly in the extractive industry sector has enabled her to make a strong contribution to the work of the BP board and the SEEAC. Her geo-political experience has been valuable during the course of the year as has her work on the nomination committee.

Iain Conn

Current position

Iain Conn is BP's chief executive, Refining and Marketing. He was appointed an executive director of BP on 1 July 2004.

Group responsibilities

In addition to his position as chief executive, Refining and Marketing, he has regional responsibility for Europe, Southern Africa and Asia. He also has responsibility for the BP brand and related matters.

Outside interests

Iain Conn is a non-executive director and the senior independent director of Rolls-Royce Holdings plc. He is chairman of the Advisory Board of Imperial College Business School and a member of the Council of Imperial College.

Career

He joined BP Oil International in 1986, working in a variety of roles in oil trading, commercial refining and exploration before becoming, on the merger between BP and Amoco in 1999, vice president of BP Amoco Exploration's mid-continent business unit.

At the end of 2000, he returned to London as group vice president and a member of the Refining and Marketing segment's executive committee, taking over responsibility in 2001 for BP's marketing operations in Europe. In 2002 he was appointed chief executive of BP Petrochemicals. Following his appointment to the board in 2004, he served for three years as group executive officer, strategic resources, in which he had responsibility for a number of group functions and regions. He was appointed chief executive, Refining and Marketing on 1 June 2007.

Relevant experience and skills

Iain Conn's career has given him extensive knowledge of a broad range of BP's businesses, particularly in the area of refining and marketing, which he has led since 2007. In this last period he has successfully remodelled BP's downstream business. He has deep knowledge of safety, manufacturing, energy markets and technology.

George David

Current position

George David was appointed a non-executive director of BP on 11 February 2008.

Board and committee activities

He is a member of the chairman's, the audit, the Gulf of Mexico and the remuneration committees.

Outside interests

George David is vice-chairman of the Peterson Institute for International Economics.

Career

He began his career with The Boston Consulting Group before joining the Otis Elevator Company in 1975. He held various roles in Otis and later in United Technologies Corporation (UTC), following Otis's merger with UTC in 1976. In 1992, he became UTC's chief operating officer. He served as UTC's chief executive officer from 1994 until 2008 and as chairman from 1997 until his retirement in 2009.

Relevant experience and skills

George David has substantial global business and financial experience through his long career with UTC, a business with significant reliance on safety and technology. He chairs BP's technology advisory council and has brought insights from that task to the board.

His considerable knowledge of the US business environment benefits considerably the work of the Gulf of Mexico committee of which he is a member and his extensive financial and commercial knowledge contributes to the work of the audit and the remuneration committees.

Ian Davis

Current position

Ian Davis was appointed a non-executive director of BP on 2 April 2010.

Board and committee activities

He is chairman of the Gulf of Mexico committee and is a member of the chairman's, the nomination and the remuneration committees.

Outside interests

Ian Davis is an independent non-executive director of Johnson & Johnson, Inc. and a senior adviser to Apax Partners LLP. He is also a non-executive member of the UK's Cabinet Office. He joined the Board of Rolls Royce Plc on 1 March 2013 and will become chairman on 2 May 2013.

Career

He spent his early career at Bowater, moving to McKinsey & Company in 1979. He was managing partner of McKinsey's practice in the UK and Ireland from 1996 to 2003. In 2003, he was appointed as chairman and worldwide managing director of McKinsey, serving in this capacity until 2009. During his career with McKinsey, he served as a consultant to a range of global organizations across the private, public and not-for-profit sectors. He retired as senior partner of McKinsey & Company on 30 July 2010.

Relevant experience and skills

Ian Davis brings significant financial and strategic experience to the board. He has had a lengthy career working with and advising global organizations and companies in the oil and gas industry. This experience has been recognized by the board in his appointments as a member of a broad range of committees and as chairman of the Gulf of Mexico committee.

As chairman of the Gulf of Mexico committee he has made a significant contribution in guiding the board's response to the various legal issues which have arisen following the Deepwater Horizon accident. During the year he stood down from the audit committee to allow him to focus his time with the Gulf of Mexico committee; he has remained a member of the remuneration committee.

Professor Dame Ann Dowling

Current position

Professor Dame Ann Dowling was appointed a non-executive director of BP on 3 February 2012.

Board and committee activities

She is a member of the SEEAC and the chairman's and the remuneration committees.

Outside interests

Dame Ann Dowling is Professor of Mechanical Engineering and Head of the Department of Engineering at the University of Cambridge. She is chair of the Physical Sciences, Engineering and Mathematics Panel in the Research Excellence Framework – the UK Government's review of research in universities.

Career

She was appointed a Professor of Mechanical Engineering in the Department of Engineering at the University of Cambridge in 1993 (the Department of Engineering is one of the leading centres for engineering research worldwide). Between 1999 and 2000 she was the Jerome C Hunsaker Visiting Professor at MIT subsequently becoming a Moore distinguished scholar at Caltech in 2001. When she returned to the University of Cambridge, she became head of the Division of Energy, Fluid Mechanics and Turbomachinery in the Department of Engineering, becoming UK lead of the Silent Aircraft Initiative in 2003, a collaboration between researchers at Cambridge and MIT. She became head of the Department of Engineering at the University of Cambridge in 2009. She was appointed director of the University Gas Turbine Partnership with Rolls-Royce in 2001 and chairman in 2009.

Between 2003 and 2008 she chaired the Rolls-Royce Propulsion and Power Systems Advisory Board. She chaired the Royal Society/Royal Academy of Engineering study on nanotechnology. She is a Fellow of the Royal Society and the Royal Academy of Engineering and is a foreign associate of the US National Academy of Engineering and of the French Academy of Sciences.

Relevant experience and skills

Dame Ann Dowling has a strong academic and engineering background.

Having initially joined the SEEAC, she is now also a member of the remuneration committee. Her contributions on both of these committees is valued as is her work with the BP technology advisory council, which she joined during the year.

Dr Brian Gilvary

Current position

Dr Brian Gilvary is BP's chief financial officer. He was appointed an executive director on 1 January 2012.

Group responsibilities

He has responsibility for BP's finance, planning, mergers and acquisitions, treasury and information technology activities.

Outside interests

Dr Brian Gilvary has no external appointments.

Career

He joined BP in 1986, after obtaining a PhD in mathematics from the University of Manchester. Following a variety of roles in the Upstream, Downstream and trading with jobs spanning across Europe and the US, he became the Downstream's chief financial officer and commercial director from 2002 to 2005.

In 2003 he was appointed a director of TNK-BP, retiring from the board in 2005 and re-joining in 2010. From 2005 to 2010 he was chief executive of integrated supply and trading, BP's commodity trading arm. In 2010 he was appointed deputy group chief financial officer with responsibility for the finance function before being appointed chief financial officer on 1 January 2012.

Relevant experience and skills

Dr Brian Gilvary has 27 years of experience within BP, gaining a strong knowledge of finance and trading, and a deep understanding of BP's assets and businesses, including its interests in Russia through his time on the board of TNK-BP.

Dr Byron Grote

Current position

Dr Byron Grote is BP's executive vice president, corporate business activities. He was appointed an executive director of BP on 3 August 2000.

He will retire from the BP board at the conclusion of the 2013 AGM.

Group responsibilities

On 1 January 2012, he became executive vice president, corporate business activities. He has accountability for BP's integrated supply and trading operations and shipping businesses, Alternative Energy business, and its technology and remediation activities.

Outside interests

Dr Byron Grote is a non-executive director of Unilever NV and Unilever PLC.

Career

He joined The Standard Oil Company of Ohio in 1979. Following a variety of roles, he became group treasurer and chief executive officer of BP finance in 1992. In 1994, he took up the position of regional chief executive in Latin America, returning to London in 1995 to become deputy chief executive officer of BP exploration. He became group chief of staff in 1997 and, following the merger of BP and Amoco, in 1999 he was appointed executive vice president, exploration and production. Following his appointment to the board in 2000, he served for two years as chief executive of BP chemicals. He was chief financial officer from 2002 until the end of 2011.

Relevant experience and skills

Dr Byron Grote has served on the board for 12 years. Throughout his tenure at BP, Byron has played a key role at critical moments of the company's history, most notably in the integrations of Amoco and Arco, and more recently in guiding BP through the financial challenges following the incidents in April 2010.

Brendan Nelson

Current position

Brendan Nelson was appointed a non-executive director of BP on 8 November 2010.

Board and committee activities

He is chairman of the audit committee and is a member of the chairman's and nomination committees.

Outside interests

Brendan Nelson is a non-executive director of The Royal Bank of Scotland Group plc where he is chairman of the group audit committee. He is a director of the Financial Skills Partnership and is deputy president of the Institute of Chartered Accountants of Scotland.

Career

He is a chartered accountant. He was made a partner of KPMG in 1984. He served as a member of the UK Board of KPMG from 2000 to 2006 subsequently being appointed vice chairman until his retirement in 2010. At KPMG International he held a number of senior positions including global chairman, banking and global chairman, financial services.

He served six years as a member of the Financial Services Practitioner Panel.

Relevant experience and skills

Brendan Nelson has had a long career in finance and auditing, particularly in the areas of financial services and trading, which qualifies him to chair the audit committee and to act as its financial expert.

This is complemented by his broader business experience. During the year he has led the work of the audit committee in continuing to strengthen the company's financial framework and has monitored the group's relationship with the external auditors. In 2012 he joined the nomination committee.

Phuthuma Nhleko

Current position

Phuthuma Nhleko was appointed a non-executive director of BP on 1 February 2011.

Board and committee activities

He is a member of the chairman's and the audit committees.

Outside interests

Phuthuma Nhleko is a non-executive director of Anglo American plc.

Career

He began his career as a civil engineer in the US and as a project manager for infrastructure developments in Southern Africa. Following this he became a senior executive of the Standard Corporate and Merchant Bank in South Africa. He later held a succession of directorships before joining MTN Group, a pan-African and Middle Eastern telephony group represented in 21 countries, as group president and chief executive officer in 2002. During his tenure at the MTN Group he led a number of substantial mergers and acquisitions transactions. He stepped down as group chief executive of MTN Group at the end of March 2011. He was formerly a director of a number of listed South African companies, including Johnnic Holdings (previously a subsidiary of the Anglo American group of companies), Nedbank Group, Bidvest Group and Alexander Forbes.

Relevant experience and skills

Phuthuma Nhleko's background in engineering and his broad experience as a chief executive of a multi-national company enables him to contribute to the board, particularly in the areas of emerging market economies and the evolution of the group's strategy. His financial and commercial experience is relevant to his work on the audit committee.

Andrew Shilston

Current position

Andrew Shilston was appointed a non-executive director of BP on 1 January 2012 and became BP's senior independent director on 12 April 2012.

Board and committee activities

He is a member of the chairman's and the audit committees and attends the nomination committee.

Outside interests

Andrew Shilston is a non-executive director of Circle Holdings plc and chairman of the Morgan Crucible Company plc.

Career

He trained as a chartered accountant before joining BP as a management accountant. He subsequently joined Abbott Laboratories before moving to Enterprise Oil plc in 1984 at the time of flotation. In 1989 he became treasurer of Enterprise Oil and was appointed finance director in 1993. After the sale of Enterprise Oil to Shell in 2002, in 2003 he became finance director of Rolls-Royce plc until his retirement on 31 December 2011.

He has served as a non-executive director on the board of Cairn Energy plc where he chaired the audit committee.

Relevant experience and skills

Andrew Shilston has had a long career in finance within the oil and gas industry. His knowledge and experience as a chief financial officer, firstly in Enterprise Oil and then Rolls-Royce, and as audit committee chairman at Cairn Energy makes him well suited as a member of BP's audit committee. He has also provided valuable insight to the work of the Russia committee. As senior independent director he has attended meetings of the nomination committee.

David Jackson

Current position

David Jackson was appointed company secretary in 2003. A solicitor, he is a director of BP Pension Trustees Limited.

Executive team

As at 6 March 2013

The executive team represents the principal executive leadership of the BP group. Its membership includes BP's executive directors (Bob Dudley, Iain Conn, Dr Brian Gilvary and Dr Byron Grote) whose biographies appear on pages 105-108) and the senior management listed below.

Mark Bly

Current position

Mark Bly is BP's special advisor to the group chief executive.

Career

Mark Bly joined BP in 1984. From 1986 to 1996, he worked on various engineering and commercial leadership assignments in Houston, a period when BP was establishing itself in the Deepwater Gulf of Mexico. Following which he held business unit leader posts in Alaska and the North Sea as well as strategic performance unit leader for North American Gas. In 2007 he became group vice president, exploration and production (Gulf of Mexico, Trinidad, Angola, North Africa and Egypt) and a member of the exploration and production operating committee.

In 2008 he became group head of safety and operations, with accountability for group level disciplines including projects, operations, engineering, health, safety, security, and environment. In that capacity, he looked after group wide operating management system implementation, capability programs, and audit.

In October 2010 Mark was appointed executive vice president of safety and operational risk. He stepped down from this role on 15 February 2013 and from the BP executive team at this date.

Rupert Bondy

Current position

Rupert Bondy is BP's group general counsel.

Group responsibilities

Rupert Bondy is responsible for legal and compliance matters across the BP group.

Career

Rupert Bondy began his career as a lawyer in private practice, with a focus on mergers and acquisitions. In 1989 he joined US law firm Morrison & Foerster, working in San Francisco, London and New York, and from 1994 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 to form GlaxoSmithKline (GSK) he was appointed senior vice president and general counsel of GlaxoSmithKline in 2001.

In May 2008 he joined the BP group, where he is the group general counsel.

Dr Mike Daly

Current position

Dr Mike Daly is BP's executive vice president, exploration.

Group responsibilities

Dr Mike Daly is accountable for the leadership of BP's access, exploration and resource appraisal activities and the long-term replacement of BP's resource base.

Career

Dr Daly joined BP Exploration in 1986, working as a technical specialist in structural geology. In the early 1990's he joined BP's global basin analysis group that set the direction of BP's exploration strategy. This work has underpinned BP's exploration and reserves replacement performance for two decades. Following this strategic work he has occupied a series of exploration business and functional roles in South America, the North Sea and new business development globally.

In 2000 he became the president for BP's Middle East and South Asia businesses. In July 2006, Dr Daly was appointed BP's Head of Exploration and New Business Development and in October 2010 was appointed executive vice president, exploration.

External roles

Dr Daly is a member of the board of British Geological Survey and a visiting professor in natural resources at Oxford University. He is also a member of the Arctic Council of the World Economic Forum.

Bob Fryar

Current position

Bob Fryar is BP's executive vice president, safety and operational risk.

Group responsibilities

Bob is responsible for strengthening safety, operational risk management, and the systematic management of operations across the BP corporate group. He is Group Head of Safety and Operations, with accountability for group-level disciplines including projects, operations, engineering, health, safety, security, and environment. In this capacity, he looks after group-wide operating management, system implementation, capability programs and audit.

Career

Bob Fryar has 27 years' experience in the oil and gas industry having joined Amoco Production Company in 1985. Most recently Bob was chief executive officer for BP Angola and in his prior role vice president of operations performance unit for BP Trinidad.

Prior to joining BP Trinidad in January 2003, Bob served in a variety of engineering and management positions in the onshore US and deepwater Gulf of Mexico including petroleum engineer, field manager, operations manager, resource manager, asset manager and delivery manager. In addition, he worked on the Vastar integration team.

In October 2010 to February 2013 Bob Fryar was executive vice president production division and was accountable for safe and compliant exploration and production operations and stewardship of resources across all regions. In addition, he was also responsible for local government and stakeholder management, integration of all exploration and production activities at the regional level, technical excellence across safety and operational risk and subsurface, and a robust operating management system to ensure safety, quality and compliance of production activities.

Andy Hopwood

Current position

Andy Hopwood is BP's chief operating officer, strategy and regions, Upstream.

Group responsibilities

Andy Hopwood is responsible for BP's upstream strategy, including changes to its portfolio and investment planning. He is also responsible for the upstream regional 'footprint' through leadership of its regional presidents, who are the upstream's senior leaders in the regions where the upstream operates.

Career

After joining BP in 1980 as a petroleum engineer, Andy Hopwood gained ten years of operating experience in the North Sea, Wytch Farm, and Indonesia, and developing expertise in reservoir engineering in BP's London headquarters.

In 1989 Andy joined the corporate planning team supporting the formulation of BP's exploration strategy. He also played an integral role in executing the subsequent rationalization of BP's portfolio, divesting BP's Canadian and Egyptian assets.

Following this corporate work, his international endeavours led to positions in South America, first in Mexico and then as commercial manager for BP's Venezuela business, prior to a return to London as the exploration and production planning manager.

In 1999, he was appointed business unit leader in Azerbaijan. He returned to London in 2001 as the Upstream chief of staff, before becoming business unit leader in Trinidad. In 2005 he moved to Houston to become strategic performance unit leader for the North American gas business.

In 2009, he joined the upstream executive as head of portfolio and technology and in October 2010 he was appointed executive vice president, exploration and production, strategy and integration. In 2013 he was appointed chief operating officer, strategy and regions, Upstream.

External roles

Andy serves as chair of the BP Foundation.

Bernard Looney

Current position

Bernard Looney is BP's chief operating officer, production.

Group responsibilities

Bernard Looney is responsible for production operations, well operations, supply-chain management and engineering in the upstream.

Career

Bernard Looney joined BP in 1991 as a drilling engineer, working in the North Sea, Vietnam and the Gulf of Mexico. In 2001 Bernard took on responsibility for drilling operations on Thunder Horse in the Deepwater Gulf of Mexico.

In 2005 Bernard became senior vice president within BP Alaska, before moving in 2007 to be head of the group chief executive's office.

In 2009 he became the managing director of BP's North Sea business in the UK and Norway.

Bernard became executive vice president, developments, in October 2010. He took up his current role in February 2013.

External roles

Bernard is a member of the Stanford University Graduate School of Business Advisory Council and a Fellow of the Energy Institute.

Lamar McKay

Current position

Lamar McKay is BP's chief executive, Upstream.

Group responsibilities

Lamar McKay is responsible for the combined Upstream business which consists of exploration, development and production.

Career

Lamar McKay started his career in 1980 with Amoco and has held a broad range of positions. In 1993, he became general manager for the Arkoma Basin, and in 1997 moved into the role of business unit leader for the Gulf of Mexico Shelf.

During 1998-2000, he worked on the BP-Amoco merger and served as head of strategy and planning for the worldwide exploration and production business in London. In 2000, he became business unit leader for the Central North Sea in Aberdeen, Scotland. In 2001, Lamar became chief of staff for the worldwide exploration and production business, and subsequently served as chief of staff to BP's deputy group chief executive.

Lamar became group vice president, Russia and Kazakhstan in 2003 where he was responsible for BP's Upstream businesses, including BP's interest in the TNK-BP joint venture. He served as a member of the board of directors of TNK-BP from February 2004 to May 2007.

In May 2007, Lamar moved to Houston to assume the role of senior group vice president, BP p.l.c. and executive vice president, BP America where he led BP's efforts to resolve various issues involving the Texas City refinery, Prudhoe Bay field and US trading business. In June 2008, he became executive vice president, special projects focusing on Russia where he led BP's efforts to restructure the governance framework for TNK-BP.

In February 2009, Lamar was appointed chairman and president of BP America Inc, serving as BP's chief representative in the US. In October 2010, he additionally assumed the role of chief executive officer and president for the Gulf Coast Restoration Organization.

On 1 January 2013, he became chief executive, Upstream.

External roles

Lamar is a member of the American Petroleum Institute's Executive Committee, the MIT's External Advisory Board; the University of Houston President's Energy Advisory Board; and the Mississippi State University Dean's Advisory Council.

Dev Sanyal

Current position

Dev Sanyal is BP's executive vice president, and group chief of staff.

Group responsibilities

Dev Sanyal is the accountable executive for all of BP's corporate activities in central programme management, government and political affairs, policy, group risk management, economics and competitor intelligence.

Career

Dev Sanyal joined BP in 1989 and has held a variety of international roles in London, Athens, Istanbul, Vienna and Dubai. He was appointed chief executive, BP Eastern Mediterranean Fuels in 1999. In 2002, he moved to London as chief of staff of BP's worldwide downstream businesses. In November 2003, he was appointed chief executive officer of Air BP. In June 2006, he was appointed head of the group chief executive's office. He was appointed group vice president and group treasurer in 2007. During this period, he was also chairman of BP Investment Management Ltd and accountable for the group's aluminium interests. In January 2012, he became executive vice president, and group chief of staff.

External roles

Dev is a member of the Accenture Global Energy Board, the European Advisory Board of The Fletcher School of Law and Diplomacy and Trustee of the Career Academy Foundation.

Helmut Schuster

Current position

Helmut Schuster is BP's executive vice president, group human resources director.

Group responsibilities

Helmut Schuster became group human resources director on 1 March 2011. In this role he holds accountabilities for the BP human resources function.

Career

Helmut Schuster began his career working for Henkel in a marketing capacity. Since joining BP in 1989 Helmut has held a number of major leadership roles. He has worked in BP in the US, UK and continental Europe and within most parts of refining, marketing, trading and gas and power. Before taking on his current role his portfolio of responsibilities as a vice president, human resources included the refining and marketing segment of BP, and corporate and functions. This role saw him leading the people agenda for roughly 60,000 people across the globe and includes businesses such as petrochemicals, fuels value chains, lubricants and functional experts across the corporation.

How the board works

BP's governance framework

BP's system of governance begins with the board and is reflected in the governance of our subsidiaries. The governance framework is outlined in the BP board governance principles which sets out the role of the board, its processes and its relationship with executive management. These can be found on *bp.com/governance*.

The board's core activities are:

→ 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 planning.

The board seeks to set the 'tone from the top' for the organization by considering specific issues, including health, safety, the environment and BP's reputation and works with management to set the values of the company, which are then reflected in more detail in the company's code of conduct.

Who's on the board?

As at 31 December 2012 the board had 15 directors – a chairman, four executive directors and 10 non-executive directors (see page 104).

The nomination committee keeps the composition of the board under review from the perspective of the mix of skills and experience of existing members and the likely tenure of each director. Details of the current skillset of the board and the skills/competencies that the nomination committee has prioritized for future non-executive director appointments is outlined in the report of the nomination committee on pages 125-126.

Role of the chairman

The board is chaired by Carl-Henric Svanberg. The chairman provides leadership of the board and is the main point of contact between the board and management. The chairman speaks on behalf of the board to shareholders and other parties and ensures that systems are in place to provide directors with accurate, timely and clear information to enable the board to consider matters before it and is also responsible for the integrity and effectiveness of the BP board governance principles.

Role of the group chief executive

Bob Dudley is the group chief executive. Through delegation from the board he is responsible for executive management of the group and is supported by the executive team, which he chairs. Membership of the executive team is set out on pages 109-111.

Role of the senior independent director

The senior independent director (SID) is Andrew Shilston, who is available to shareholders if they have concerns that cannot be addressed through normal channels.

In view of the relatively short service of Andrew Shilston, Antony Burgmans, the longest serving non-executive director acts as an internal sounding board for the chairman and serves as intermediary for the other directors with the chairman when necessary.

Neither the chairman nor the SID are employed as executives of the group. The board maintains a succession plan for the chairman and SID, in addition to the group chief executive and senior management.

Director independence

The governance principles require the non-executive directors 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 those non-executive directors who served during 2012 were and continued to be independent.

The board also satisfied itself that there is no compromise to the independence of, or existence of conflicts of interest for 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 each board meeting. The nomination committee keeps under review the nature of non-executive directors' other interests to ensure that the effectiveness of the board is not compromised.

Succession: board and committee membership

The following changes took place to the composition of the board in 2012:

- Dr Brian Gilvary joined the board as an executive director and chief financial officer on 1 January 2012.
- Andrew Shilston joined the board as a non-executive director on 1 January 2012, and became senior independent director from April 2012.
- Professor Dame Ann Dowling joined the board as a non-executive director on 3 February 2012.
- Sir William Castell retired from the board at the AGM in April 2012.

Dr Byron Grote, executive director with responsibility for BP's integrated supply and trading operations, Alternative Energy, shipping, technology and remediation activities will retire from the board at the AGM in April 2013.

Changes to committee membership during 2012 included Ian Davis stepping down as a member of the audit committee on 3 February 2012 and Admiral Frank Bowman joining the Gulf of Mexico committee on the same date. Upon their appointment to the board, Andrew Shilston joined the audit committee and Professor Dame Ann Dowling joined the safety, ethics and environment assurance committee (SEEAC). Professor Dowling later joined the remuneration committee on 25 July 2012. Following the retirement of Sir William Castell in April, Brendan Nelson and Paul Anderson joined the nomination committee. Andrew Shilston, who succeeded Sir William as senior independent director, attends the committee in this capacity.

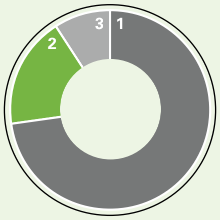
Ad-hoc board committee – Russia

An ad-hoc board committee was established in June 2012 to oversee issues relating to the sale of BP's share in TNK-BP. This committee, known as the Russia committee, is chaired by Antony Burgmans and membership includes Andrew Shilston and Paul Anderson. Carl-Henric Svanberg and Bob Dudley attend the committee meetings. The committee received regular and detailed reports on the process for the sale of the company's stake in TNK-BP and supported the proposal to the board of the binding sale and purchase agreements that were eventually executed with Rosneft. The committee will continue to receive updates through to closing of the agreements with Rosneft (currently anticipated to occur in the first half of 2013).

Appointment and tenure

The chairman and our non-executive directors (NEDs) serve on the basis of letters of appointment. Letters of appointment (and service contracts for our executive directors) are available for inspection at the registered office of the company. BP does not place a term limit on director's service as it proposes all directors for annual re-election by shareholders (a practice followed since 2004).

Board tenure as at 31 December 2012



■ 1. 0-3 years	8 NEDs	73%
🟩 2. 4-6 years	2 NEDs	18%
▨ 3. 7-9 years	1 NED	9%

Antony Burgmans joined the board in February 2004 and by the 2013 AGM will have served nine years as a director. The board has asked him to stay on for an additional three years as it believes that his experience as the longest serving board director provides valuable insight and continuity.

The board considers that he remains independent despite his length of tenure in view of his clarity of thought, his approach in evaluating events of the last few years and the interaction he has demonstrated in his work on the SEEAC, the nomination and remuneration committees and his chairmanship of the ad-hoc board committee on Russia.

Time commitment and outside appointments

Letters of appointment for non-executive directors do not set out a fixed time commitment for board duties as it is anticipated that the time required by directors may fluctuate depending on demands of the business and other events. It is however expected that directors will allocate sufficient time to the company to perform their duties effectively. This practice was reviewed and confirmed by the nomination committee in 2012. The chairman's appointment letter sets out the time commitment expected of him.

Executive directors are permitted to take up one external board appointment, subject to the agreement of the chairman. Fees received for an external appointment may be retained by the executive director and are reported in the directors' remuneration report (see page 127).

Diversity

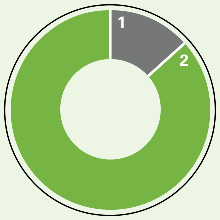
BP recognizes the importance of diversity, including gender, at all levels of the company as well as the board. The company is committed to increasing diversity across its operations and has in place a wide range of activities to support the development and promotion of talented individuals, including women.

In 2011 the board confirmed its support for the work of Lord Davies and his report on Women on Boards and aimed to increase the number of women on the board by two by 2013 and aspired to reach his recommendation of 25% female board representation by 2015. In 2012, the chairman joined the 30% Club (a group of chairman who have voluntarily committed to bring more women onto UK corporate boards).

In 2012, the nomination committee agreed metrics to monitor the board's diversity mix and implementation of the board's diversity policy. These metrics include the gender split and geographic background of the BP board and are shown below. The board also considered diversity as part of the annual evaluation of its performance and effectiveness.

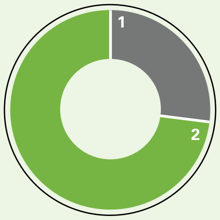
Board diversity as at 31 December 2012

Gender



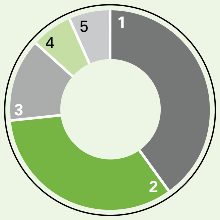
■ 1. Female directors	2
🟩 2. Male directors	13

Independence



■ 1. Executive directors	27%
🟩 2. Non-executive directors	73%

Geographic background



■ 1. UK	6
🟩 2. US	5
▨ 3. Europe excluding UK	2
▨ 4. Rest of World	1
▨ 5. UK/US dual citizenship	1

The work of the BP board in 2012

The board meets in person or by teleconference. Nine meetings were scheduled for 2012, but additional board meetings were called principally to discuss legal issues in the US and the sale of BP's share in TNK-BP, meaning the board met 19 times during the year, with nine of these meetings taking place by telephone. These telephone meetings were by their nature called at short notice and directors who were unable to attend (often due to travel commitments) were briefed separately outside the meeting. For director attendance at board and committee meetings, see the table on page 120.

The board's agenda for the year has focused on key areas of strategy, assurance, risk and reputation.

Board activities

Strategy

- Strategy discussions
- Annual plan
- Russia
- Technology
- Brazil biofuels
- North American gas
- Strategy development process and planning methodology
- Competitor outlook
- Wind

Assurance

- Change management programme
- Legal updates
- Major project delivery and effectiveness of investment
- Integrated supply and trading review

Risk

- Group risks review
- Crisis and reputation management
- Global economic climate
- Organizational capability
- Russia
- Delivery of the 10-point plan

Reputation

- External reputation reports
- Employee surveys/Pulse tracker
- AGM feedback
- Investor audit and shareholder feedback

Strategy

The evolution and development of the group's strategy was discussed at each of the regular meetings of the board during the year. These discussions were held against the background of the steps being taken to resolve uncertainties in the US and Russia. More detailed discussions on long-term strategic options were held at two strategy away-days in 2012. Key strategic elements examined included North American gas, Russia, technology and biofuels in Brazil. The board also reviewed the company's planning methodology and strategy development process, looking at energy market structures, long-term price ranges and the assumptions used for BP's investment evaluations.

Assurance

The board received regular updates during the year on legal issues, in particular on litigation and enquiries resulting from events in the Gulf of Mexico. It examined the delivery of major projects and the effectiveness of investment and received a review of BP's integrated supply and trading business.

The board assessed the effectiveness of the group's system of internal controls and risk management and reviewed its financial performance. It received an update on the progress of BP's change management programme, implemented at the end of 2010, and reviewed the work of the central programme management office established to ensure there is an integrated, company-wide approach to the change programme and to minimize disruption in the businesses. The board also received a report from Duane Wilson, the independent expert appointed by the board to provide an objective assessment of BP's progress in implementing the recommendations of the BP US Refineries Independent Review Panel.

Risk

The board and its monitoring committees (audit, SEEAC and Gulf of Mexico) monitored the group risks which had been allocated following the board's review of the annual plan at the end of 2011. The annual plan and the group strategy are central to BP's risk management programme as they provide a framework for the board to consider significant risks and manage the group's overall risk exposure as well as underpin the model of delegation and assurance for the board in its oversight of executive management and other activities.

The group risks allocated to and reviewed by the board over the year included risks associated with the global macroeconomic outlook, the delivery of BP's 10-point plan, the group's exposure to Russia, crisis management, reputational impact and organizational capability. The board held a mid-year discussion to consider any changes required to the allocation of group risks and to confirm the schedule for oversight and governance of these risks by the board and its committees.

Reputation

The board discussed the risks relating to the reputation of the group globally, but in particular relating to the US, and also the processes the company has in place to manage these risks. The result of an external reputation survey was considered, which examined BP's reputation in key markets, including the UK and US. From an internal perspective, feedback from the regular, global survey of employees was examined following the launch of BP's renewed values and updated code of conduct at the end of 2011.

In addition to understanding feedback from external focus groups and employees, the board received regular reports which outlined shareholder sentiment on the company. This includes analyst reports, the annual investor audit, feedback from shareholders on voting on the company's resolutions at the AGM and follow-up discussions post investor roadshows and other one-to-one shareholder meetings (see shareholder engagement on page 116).

Board effectiveness

Induction and board learning

On joining BP, non-executive directors are given a tailored induction programme. This includes one-to-one meetings with management, the external auditors and site visits to operations. The induction will also cover the board committees that a director will join. During the year induction programmes were organized for Andrew Shilston and Professor Dame Ann Dowling. An example of the induction programme given to recently appointed non-executive directors is set out below.

Director induction programme

Board and governance

- BP's board governance model, directors' duties, interests and potential conflicts.
- Committee induction.

BP's business

- Upstream (exploration, development, production, overview of our operations).
- Downstream.
- Alternative Energy.
- Strategy and planning.
- BP's performance relative to its competitors.

Functional input

- Finance and tax.
- Controls, external auditors and internal audit.
- Human resources.
- Ethics and compliance.
- Safety and operational risk (S&OR), BP's operating management system (OMS) and environmental performance.
- Research and technology.
- Engineering.
- Trading.

The board's learning is continued through board and committee briefings and site visits. In 2012, the board received briefings on key aspects of BP's activities, including the competitive context for the company and BP's projections for energy supply and demand. At the board meeting in Houston, non-executive directors were given the opportunity to meet BP's wider US leadership group at informal lunch and dinner events. In the autumn, the board met leading US political figures in advance of the US presidential elections.

Non-executive directors are expected to attend at least one site visit per year. During 2012 the board made a number of visits, including to BP's Texas paraxylene site, fracking operations in East Texas, the Thunderhorse platform in the Gulf of Mexico and the Buncefield terminal in the UK. The chairman visited the Deepwater Gunashli platform and Sangachal terminal in Azerbaijan, the Kinneil terminal in the North Sea and the Greater Plutonio floating production, storage and offloading facility in Angola. He also held employee town halls and met with regional leadership teams whilst visiting BP's offices in Azerbaijan, Tokyo, the North Sea and Angola.

After each site visit, the board or appropriate committee is briefed on the impressions gained by directors attending the visit.

Board visit to US hydraulic fracturing operations

In May, six non-executive directors travelled to East Texas to visit our North America gas operations for a first-hand look at onshore natural gas production sites and the technique known as hydraulic fracturing or 'fracking'. The visit was an opportunity for the board to learn more about BP's natural gas business in the US, and in particular about production from unconventional gas resources. More than 80% of BP's onshore gas is from unconventional gas resources such as shale gas, tight gas and coalbed methane.

Following a site specific safety briefing, the directors toured a drilling rig at the well site where they were given an overview of the drilling process and saw a hydraulic fracturing set up with pump trucks and other associated equipment. The tour also included a visit to the production facility, where board members obtained insights on the water and gas separation operations, and how product coming from wells in the area is handled prior to processing.

In commenting on his impressions of the visit, the chairman of SEEAC Paul Anderson said: "We have a professional, dedicated team that is doing a good and responsible job of developing the resource."

Board evaluation

BP undertakes an annual review of the board, its committees and individual directors. The chairman's own performance is evaluated by the chairman's committee (led by Antony Burgmans in consultation with the senior independent director).

For the past three years an external review of the board's performance has been undertaken, and for 2012 the board undertook an evaluation facilitated by external legal counsel on the basis of a questionnaire, which tested key areas of the board's work including strategy, monitoring, risk and governance processes. The evaluation also considered the balance of skills, experience, independence and knowledge of the company on the board, its diversity (including gender), how the board works together as a unit and other factors relevant to its effectiveness. The results of the review were discussed at the board and individually at each committee in January 2013.

Key conclusions from the evaluation

The review concluded that there had been significant progress in dealing with major strategic issues over the year and there had been a continued improvement in board processes, particularly in the areas of time management and board materials.

Going forward, it was agreed that the emphasis on improving board processes would continue and that as the group transitioned to a more stable business environment, the board would focus on re-aligning its agenda to increase the focus on strategic issues. There would also be more use of forward agenda planning to enable this to be realised.

Tracking issues from our previous evaluation

In 2012, the board progressed recommendations of the 2011 board evaluation. The board continued to track the risk management review and the implementation of enhancements to the company's risk management system. Emphasis was given to key governance processes raised by the 2011 evaluation, with board and committee papers adopting a common template and risk matrices in board materials using a consistent methodology aligned with the group's risk management reports. There was also increased focus on financial and non-financial metrics used by the board and this will continue into 2013.

A further outcome of the last evaluation was the wish to move back to a steady state of operation. However, developments during the year led to an increase in the scheduled number of board meetings from 11 to 19; the board will again endeavour to find this equilibrium over the course of 2013.

Shareholder engagement

The company operates an active programme of investor dialogue, including regular investor meetings, which provides an opportunity to communicate with shareholders and analysts and to understand their views on the company's performance and strategy. The board receives feedback on investor views through results of the investor audit and reports from management and directors who have had shareholder interaction over the year.

Shareholder engagement cycle 2012

January	→ *BP 2030 Energy Outlook* presentation
February	→ 4Q results and strategy presentation → Investor roadshows with executive management
March	→ UKSA private shareholder meeting → Chairman and committee chairs meeting → SRI roadshow on *BP Sustainability Review* → Plaintiff's Steering Committee settlement investor call
April	→ Annual General Meeting
May	→ 1Q results
June	→ Launch of *BP Statistical Review of World Energy*
July	→ 2Q results
September	→ Oil and gas conferences
October	→ Group SRI meeting → Engagement on remuneration
November	→ 3Q results and investor update → Oil sands webinar → DoJ resolution investor call
December	→ Upstream investor day

Institutional investors

Executive directors and senior management regularly meet with institutional investors through roadshow, group and one-to-one meetings. Events for socially responsible investors (SRI) are held throughout the year, including a group meeting which discussed managing safety and operational risk in BP, people capability, managing potential risk in wells and the company's progress on the Bly Report recommendations. Whilst held in the UK, this meeting was webcast for US and overseas investors.

During the year the chairman, senior independent director and chairs of the SEEA and remuneration committees held one-to-one meetings with institutional investors to discuss strategy, the board's view on the company's performance, governance, operational practices and the group's remuneration structure. An annual investor event was held in March 2012 with the chairman and chairs of the board committees. This meeting enables BP's largest shareholders to discuss the work of the board and its committees, and for non-executive directors to engage in dialogue with investors. It is intended that a similar event is held in March 2013.

Materials from investor presentations, including information on the work of the board and its committees can be downloaded at *bp.com/investors*.

Private investors

An event for private investors was held in 2012, organized in conjunction with the UK Shareholders' Association (UKSA). A group of 40 private shareholders listened to presentations from the chairman and head of investor relations on BP's annual results, strategy and the work of the board. The event enabled shareholders to ask questions on the company's activities and for the company to receive direct private shareholder feedback. The event will be repeated in 2013.

BP's 'lost shareholder' programme was continued over the year. This returns shares and unclaimed dividends to shareholders who have failed to keep their contact details up to date. The amount of unclaimed dividends reunited in 2012 was approximately £750,000.

AGM

BP's shareholder base is geographically diverse and a webcast and an advance electronic and paper voting service is offered to make the meeting accessible to those who cannot attend in person.

The voting levels for the 2012 AGM saw an increase over the previous year to 63.2% (versus 60.6% in 2011). A webcast, speeches and presentations from the AGM are available on *bp.com/agm* after the meeting, together with the outcome of voting on each resolution. At the 2012 AGM all resolutions were passed with votes ranging from 88.2%-99.8%. As in previous years, the board received a report after the AGM giving a breakdown of the vote and feedback from large shareholders on their voting decisions for the meeting.

Geographical distribution of share ownership as at 31 December 2012 (%)[a]

[a] Represents BP's best efforts to determine ownership of the group's shares, based on analysis of the year-end share register.

[b] Miscellaneous represents unidentified shares that are awaiting confirmation of the identity of the holder and the nature of their interest in the shares following enquiries made under Section 793 of the Companies Act 2006.

Risk in BP

Risk management is the foundation for reinforcing safety, building trust and growing value. In 2012 BP continued to review, refresh and enhance its management of risk.

The role of the board

One of the key tasks of the board is to satisfy itself that the material risks to BP are identified and understood and that systems of risk management, compliance and control are in place to mitigate such risks. The board 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.

Board governance includes monitoring committees comprised of those directors best suited to serve on them, including the audit; the safety, ethics and environment assurance; and the Gulf of Mexico committees.

The role of executive management

The group chief executive maintains BP's system of internal control. The system of internal control comprises the holistic set of management systems, organizational structures, processes, standards and behaviours that are employed to conduct the business of BP. The system is designed to meet the expectations of internal control of the Corporate Governance Code in the UK and of the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in the US.

Key elements of the system include: BP's set of corporate values, behaviours and code of conduct; group strategic framework, including risk management; how the company is organized and managed; and how we verify that the system is working. BP's risk management system is an integral part of its system of internal control, and is designed to be a simple, consistent and clear framework for managing and reporting all risk from the group's operations to the board.

Executive committees are established by the group chief executive to assist him in discharging his board delegations. Their role includes setting policy, making decisions and overseeing the management of risks and performance. The executive committees are: executive team meeting (ETM); group operations risk committee (GORC); group financial risk committee (GFRC); group disclosure committee (GDC); group people committee (GPC); resource commitments meeting (RCM); and group ethics and compliance committee (GECC).

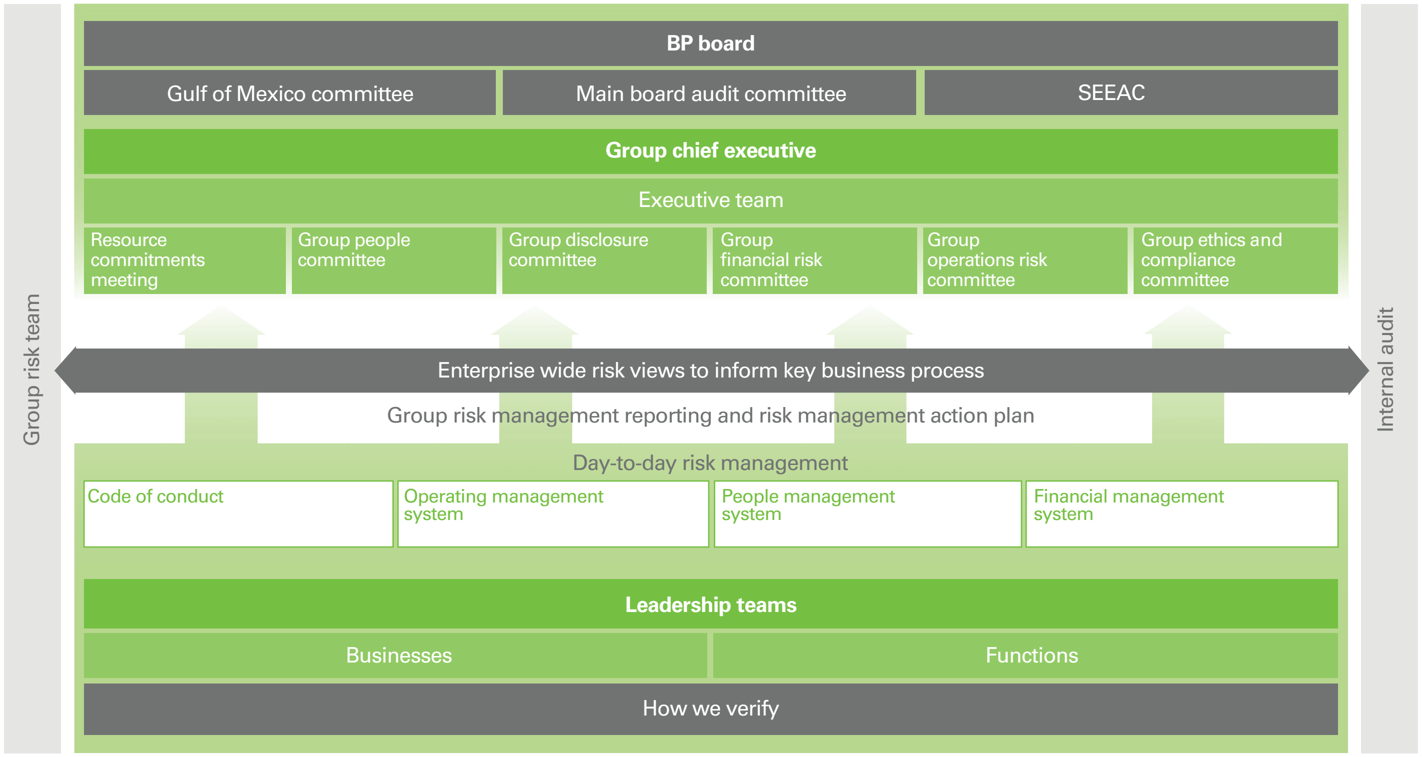
Review of risk management

In 2012, the review to enhance the clarity, consistency and simplicity of BP's risk management system was completed.

We have embedded common language, concepts and templates for consistent reporting on risks and risk management; enhancements to board and executive processes; and greater alignment of risk management activities and business processes. These improvements build from BP's existing management systems, standards and practices.

A group risk team, effective 1 January 2013, has been established to hold a view of the group risk profile to inform key businesses processes and decisions; co-ordinate group risk reporting activities; and maintain the group risk management system.

Risk management structures



BP's risk management system

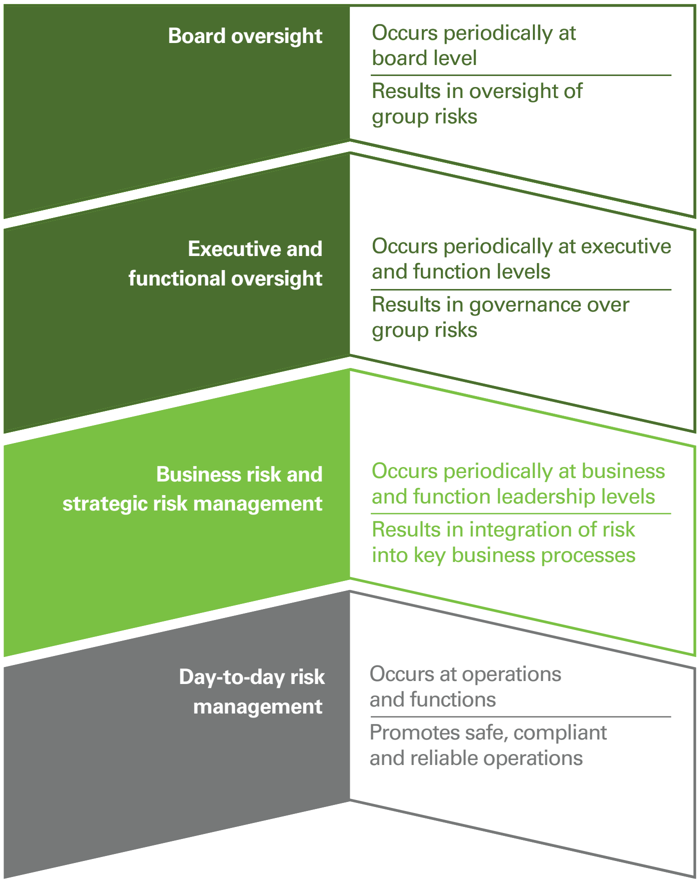
BP's risk management system focuses on three levels of activity:

Day-to-day risk management – the system helps facilitate day-to-day risk management in the group's operations and functions, with the approach varying according to the types of risk faced. Risks are to be identified and managed, and actions to improve the management of risk are to be put in place where necessary. The aim is to address each different type of risk as well as we can – promoting safe, compliant and reliable operations.

Business and strategic risk management – for BP's businesses and functions, risks arising are to be collated periodically, risk management activities are to be assessed, and any necessary further improvements or actions are to be planned. The system is designed to facilitate this by incorporating a standardized form called the risk management report (RMR), for businesses and functions to report consistently the risks they face for management consideration, challenge, resource allocation and intervention. This enables the integration of risk into key business processes such as strategy, planning, performance management, resource allocation and project appraisal.

Board, executive and functional oversight – the system facilitates executive and board oversight and governance over the management of significant risks. It requires executive team level involvement in the finalization of risk management activities and improvement plans for the group's most significant individual risks. Using the consistent bottom-up risk identification and assessment process, coupled with top-down executive overview, the system requires that the most significant risks requiring oversight are identified. Oversight of the management of these risks is to be provided through regular review by the board or one of its committees.

Risk management: from operations to the board



BP's risk management system assists in:

- Understanding the risk environment for input into the strategy.
- Understanding which risk types we operate with, given the strategy.
- Identifying and assessing the specific risks and the potential exposure they may represent.
- Decision-making on how best to deal with those risks to manage overall potential exposure.
- Active management of identified risks.
- Reporting to management and the board about how those risks are managed, and monitoring of potential exposure.
- Obtaining assurance over the effectiveness of the management of those risks.
- Intervening for improvements in the management of those risks where necessary.
- Considering the effect of the external environment and business activities on the principal activities of BP's risk management system.

The willingness to take and appropriately manage certain risk is fundamental to the success of any commercial enterprise. For example, in our upstream business we consciously place significant amounts of capital at risk in exploring for new hydrocarbon resources. Where this exploration is successful, we would generally expect it to lead to future increases in our proved reserves and future cash flows. However, exploration expenditure may not yield adequate returns, for example in the case of unproductive wells or discoveries that prove uneconomic to develop.

Risk management and reporting in 2012

During 2012, BP's segments, strategic performance units and functions prepared RMRs. The most significant risks were organized into common categories – strategic risks, safety and operational risks and compliance and controls risks – so they could be assessed and reported up the line in the standardized form. This helped provide an overall data set of the key risks identified, an assessment of their potential impact and likelihood on a consistent basis, information on how they were being managed and any actions planned or in progress to improve the management of risk. Based on these RMRs, together with additional executive overview, a single group RMR has been prepared. Those risks identified on the group RMR requiring particular group-level oversight in the coming year are allocated to specific board and executive committees for oversight and monitoring. These are discussed below. Also see Risk factors on pages 38-44 for a description of the material risks we face in our business.

Executive and board oversight of risk

The executive and board examine particular group risks both on a periodic basis and as part of the development and review of the annual plan. The board also conducts an annual review of the risk management and internal control systems as required by the UK Corporate Governance Code. During the year there is flexibility to change which risks have been identified as requiring particular oversight and which have been allocated to the executive or board, in the event there are any changes to the internal or external environments or events arising.

The executive committees monitor the group risks in the following areas:

- ETM for strategic and commercial risks.
- GORC for health, safety, security and environment and operations integrity risks.
- GFRC for finance and trading risks.
- GDC for financial reporting risk.
- GPC for people risks.
- RCM for risks related to investment decisions.
- GECC for ethics and compliance risks.

Following review of the 2013 annual plan, the following risks have been allocated for review by the board and its committees:

- The board has been allocated several strategic and commercial group risks, including risks associated with the global economic climate, the delivery of BP's 10-point plan, our activities in Russia and reputation management.
- The audit committee has been allocated a number of strategic and commercial and compliance and control risks, including risks associated with treasury and trading activities, compliance with applicable laws and regulations and security threats against our digital infrastructure.
- The SEEAC has been allocated several safety and operational risks, including risks associated with conducting our operations through joint ventures where BP may not have full operational control. Other safety and operational risks the committee has been allocated include the health, safety, security and environmental risks of incidents associated with the drilling of wells, operation of facilities, pipelines and marine activity.
- The Gulf of Mexico committee has been allocated a number of strategic and commercial risks, including risks associated with the extent and timing of costs and liabilities relating to the accident and compliance with plea agreements.

Committee reports

Board and committee attendance

	Board		Audit committee		SEEAC		Remuneration committee		Gulf of Mexico committee		Nomination committee		Chairman's committee	
	a	b	a	b	a	b	a	b	a	b	a	b	a	b
Non-executive directors														
Carl-Henric Svanberg	19	19									4[c]	4	8[c]	8
Paul Anderson	19	19			6[c]	6			23	19	2	2	8	8
Admiral Frank Bowman	19	19			6	6			19	18			8	8
Antony Burgmans	19	17			6	6	5[c]	5			4	4	8	8
Cynthia Carroll	19	15			6	4					4	3	8	5
Sir William Castell	3	2			2	2			12	10	1	1	2	2
George David	19	19	11	11			5	5	23	22			8	8
Ian Davis	19	18	1	1			5	5	23[c]	23	4	4	8	8
Professor Dame Ann Dowling	18	18			5	5	3	3					6	6
Brendan Nelson	19	18	11[c]	11							2	2	8	8
Phuthuma Nhleko	19	17	11	10									8	8
Andrew Shilston	18	15	10	8									6	6
Executive directors														
Bob Dudley	19	19												
Iain Conn	19	18												
Dr Brian Gilvary	19	18												
Dr Byron Grote	19	19												

a = Total number of meetings the director was eligible to attend.
b = Total number of meetings the director did attend.
c = Committee chairman.

The attendance of certain directors was adversely affected by changes to BP's rhythm of board meetings, resulting in clashes with directors' other executive board commitments.

Audit committee

> "The committee places value on discussing issues directly with management and operational leadership, as well as seeing first-hand the group's risk and control processes in practice."

Chairman's introduction

During the year the committee has maintained focus on the review and challenge of BP's financial assessment of its responsibilities arising from the Deepwater Horizon accident. We have continued to operate a delineated model between the board's three monitoring committees of audit, SEEA and Gulf of Mexico and have found our respective areas of oversight to be effective in informing the board's view as to the nature of the uncertainties facing the company and context for ongoing litigation and enquiries.

In addition to this focus, the committee has ensured that the cycle of its normal agenda is maintained. During the year we have reviewed the areas of group-level risk allocated to the committee for oversight, namely trading and treasury, cyber security and compliance with laws and business regulations (including bribery and corruption, money laundering, competition and anti-trust and international trade regulations). We have also undertaken reviews on key aspects of BP's financial reporting processes, including the assumptions and methodology regarding provisions for litigation, environmental remediation and decommissioning. Other activities in 2012 have included monitoring major project delivery and effectiveness of investment and tracking the progress of implementing BP's finance warehouse programme.

The committee places value on discussing issues directly with management and operational leadership, as well as seeing first-hand the group's risk and control processes in practice. During the year, I have attended visits to the company's fracking operations, a paraxylene manufacturing facility in Texas and the Buncefield terminal in the UK.

In a challenging economic and political climate for business, the committee's work and the company's audit, assurance and compliance frameworks have enabled BP to maintain the integrity of the group's financial and internal controls and the identification and mitigation of risk in response to these uncertainties. The committee has an excellent mix of skills and expertise in commercial, audit and financial matters and is well prepared to face the forthcoming year.

Brendan Nelson
Committee chair

Committee members

Brendan Nelson – committee chair
George David
Ian Davis (retired from the committee on 3 February 2012)
Phuthuma Nhleko
Andrew Shilston (joined the committee 3 February 2012)

The audit committee is composed of independent, non-executive directors selected to provide a wide range of financial, international and commercial expertise appropriate to fulfil the committee's duties.

Brendan Nelson is chair of the audit committee. Formerly vice chairman of KPMG, he is chairman of the group audit committee of The Royal Bank of Scotland Group plc, deputy president of the Institute of Chartered

Accountants of Scotland and a director of the Financial Skills Partnership. The board is satisfied that Brendan Nelson is the audit committee member with recent and relevant financial experience as outlined in the UK Corporate Governance Code. It considers that the committee as a whole has an appropriate and experienced blend of commercial, financial and audit expertise to assess the issues it is required to address. The board also determined that the audit committee meets the independence criteria provisions of Rule 10A-3 of the US Securities Exchange Act of 1934 and that Brendan Nelson may be regarded as an audit committee financial expert as defined in Item 16A of Form 20-F.

Committee role and structure

The role and responsibilities of the audit committee are set out in the appendix of BP's board governance principles which is available at *bp.com/governance*. This includes responsibility for reviewing the effectiveness of the group's financial reporting, internal control policies and procedures for the identification, assessment and reporting of risk. The committee also monitors the integrity of the group's disclosure documents, keeps the relationship with the external auditors under review (including the policy on non-audit services) and monitors the effectiveness of the internal audit function.

The committee met 11 times in 2012 including three joint meetings with the SEEAC. The chairs and secretaries of the audit and SEEA committees have worked together to ensure their respective agendas neither duplicate nor omit coverage of key risk areas.

Each audit committee meeting is attended by the group chief financial officer, the group controller, the general auditor (head of internal audit) and the chief accounting officer. The lead partner of our external auditors is also present.

The committee also holds separate private sessions during the year with the external auditor, the general auditor and the group ethics and compliance officer. These sessions are held without the presence of executive management.

Committee processes

Information and advice

Information and reports for the committee are received from functional and business managers and from external sources. Like our board and other committees, the audit committee can access independent advice and counsel when needed on an unrestricted basis. During 2012, external specialist legal advice in relation to corporate reporting was provided to the committee by Sullivan & Cromwell LLP. As part of its annual evaluation, the committee reviews the adequacy of reliable and timely information from management that enables it to fulfil its responsibilities.

Training and induction

The committee received technical updates from the chief accounting officer on developments in financial reporting and accounting policy. In addition, the external auditors provided their survey on global trends in fraud and a briefing on regulatory developments impacting audit committees as a learning session.

Induction programmes are provided for new members and are tailored around their roles on the audit committee. During 2012 Andrew Shilston attended induction sessions on tax, trading operations, accounting, financial reporting and controls and the structure of BP's finance function. Individual private sessions with the external and internal auditors were also provided.

2012 committee activities

Gulf of Mexico

Whilst the Gulf of Mexico committee has considered the work of the Gulf Coast Restoration Organization (GCRO) and litigation matters, and the SEEAC has reviewed the company's implementation of the recommendations of the Bly Report, the audit committee's focus has been on financial reporting and controls. The committee has reviewed each quarter the provisions and contingencies related to the accident and their disclosure.

Financial reporting

The group's quarterly financial reports, the *BP Annual Report and Form 20-F* and the *BP Summary Review* were reviewed by the committee before recommending their publication to the board. The committee discussed with management how they had applied critical accounting policies and judgements to these documents, including key assumptions regarding provisions for litigation, environmental remediation and decommissioning. The committee held a deep review of the impairment testing process, methodology and the pricing assumptions that were utilized. In considering the robustness of the valuations, the committee referred to analysis undertaken by the external auditors. The committee also reviewed the company's methodology underpinning its disclosures relating to oil and gas reserves.

Monitoring business risk

The board periodically reviews the company's group risks and allocates monitoring of their management and/or mitigation to itself or its committees. The group risks allocated to the audit committee for 2012 included risks associated with treasury and trading, digital security and compliance with business regulations. For 2013, the board has agreed that the committee will maintain monitoring of these same group risks.

During the year, the committee undertook functional reviews of information technology and services, integrated supply and trading and the governance of major project investment. It examined the recommendations from an external review of controls in the North American gas and power trading business and tracked the progress of their close-out over the year. The committee also reviewed the lessons learned from the company's investment programme to upgrade the Whiting refinery.

Reports on the work of the group financial risk committee – the executive-level committee that provides assurance on the management of BP's financial risk – were provided during the year by the chief financial officer.

Internal control, audit and risk management

The forward agenda for the audit committee contains standing items on internal control – these include quarterly reports of internal audit findings, internal control deficiencies in financial reporting, and an annual assessment of BP's enterprise level controls.

The committee holds an annual joint meeting at the start of each year with the SEEAC to review the company's risk management and internal control systems. At this meeting, the committees review the general auditor's report on internal control and risk management systems for the previous year, with the general auditor outlining his team's findings and management's actions to remedy significant issues identified, including the outcome of work undertaken by the safety and operational risk audit team and the group's financial control team.

A further joint meeting between the two committees was held at the end of the year to review the refreshed description of the company's system of internal control which was subsequently communicated to employees in early 2013.

External auditors

In 2012 the audit committee held two private meetings with the external auditors without management being present. In addition, the chair of the audit committee met privately with the external auditors before each audit committee.

A new lead audit partner is appointed every five years and other senior audit staff are rotated every seven years. No partners or senior staff from Ernst & Young who are connected with the BP audit may transfer to the group. During the year the committee approved the appointment of a new lead partner from Ernst & Young to replace the current partner who reaches five years' service in early 2013.

Auditor objectivity and independence is safeguarded through limiting non-audit services to tax and audit-related work that fall within defined categories. For a list of those categories, the process by which non-audit work is approved when the audit committee concludes that it is in the interests of the company to purchase non-audit work from the external auditor (rather than another supplier), see the section on Principal accountants' fees and services (page 149). Non-audit work by Ernst & Young is subject to the audit committee's pre-approval policy. Non-audit work undertaken by Ernst & Young and by other accountancy firms is regularly monitored by the committee.

The audit committee annually reviews the audit fee structure and terms of engagement. Fees paid to the external auditor for the year were $54 million, of which 13% was for non-assurance work (see Financial statements – Note 16). Non-audit or non-audit-related assurance fees were largely unchanged from 2011 levels, at $7 million. Non-audit or non-audit-related assurance services consisted of tax compliance services, tax advisory services and services relating to corporate finance transactions. The audit committee is satisfied that this level of fee is appropriate in respect of the audit services provided and that an effective audit can be conducted for such a fee.

During the year, the committee considered the outcome of the Financial Reporting Council consultation on the UK Corporate Governance Code and Guidance on Audit Committees, with particular focus on provisions for tendering the external audit. The committee has undertaken preparatory work to understand the potential for other audit firms to participate in a tender should this be triggered by criteria which has been agreed with management, including independence, quality of service, audit quality, value for money and regulatory changes. The committee will keep this under review going forward.

The effectiveness of the external auditors is evaluated by the audit committee each year. The auditor assessment tool is completed on an annual basis and examines five main performance criteria – robustness of the audit process, independence and objectivity, quality of delivery, quality of people and service, and value-added advice. The composition of the audit team is reviewed annually and the committee has the opportunity to assess specific technical capabilities in the audit firm when addressing specialist topics, such as tax and trading.

The committee has recommended to the board that the reappointment of Ernst & Young as the company's external auditors be proposed to shareholders at the 2013 AGM.

Internal audit

The committee receives quarterly reports from the general auditor which outline the planned schedule of audits as well as tracking key findings and any material actions that are overdue or have been rescheduled. In reviewing the audit programme proposed each year, the committee looks at whether it believes key risks facing the company have been appropriately addressed. The forward programme of internal audit work was reviewed by the audit and SEEA committees during the year.

The general auditor met privately with the committee once during the year, without the presence of executive management or the external auditors. In addition, the committee chair holds regular meetings with the general auditor between committee meetings.

The committee reviewed with the general auditor the number and expertise of his team's staff resources. The committee was satisfied that internal audit had resources sufficient to fulfil the function's role, that it had the appropriate access it required to information and that management had responded to the results of audit findings in a timely manner.

Other activities

One of the joint meetings with the SEEAC was held to review the annual certification report of compliance with the BP code of conduct which is signed by the group chief executive. During the year the committee monitors non-compliance with the BP code of conduct through quarterly reports by the group ethics and compliance officer. At a further joint meeting with the SEEAC, the committee reviewed the work of the ethics and compliance function and its programme for 2013.

The company's employee concerns programme, OpenTalk, has been adopted by the committee for whistle-blower monitoring, and all financial issues that have been flagged through the programme are reviewed by the committee. The committee also receives quarterly updates on fraud and misconduct.

Committee evaluation

Each year the audit committee examines its performance and effectiveness. In 2012, the committee used a survey covering similar questions to 2011 in order to identify trends. Key areas covered included the clarity of its role and responsibilities, the balance of skills and knowledge among its members and the quality and timeliness of information received. Specific areas identified for focus in 2013 included committee training and focus on the length and format of materials.

Safety, ethics and environment assurance committee (SEEAC)

> “SEEAC has spent considerable time over the past year both in terms of understanding and monitoring key group risks.”

Chairman's introduction

The SEEAC remains committed to monitor closely and provide constructive challenge to management in its drive for safe and reliable operations at all times. The SEEAC has spent considerable time over the past year both in terms of understanding and monitoring key group risks as described below. Additionally it continued to monitor the group's response to the 26 recommendations that were made in BP's investigation report (the Bly Report) into the tragic accident in April 2010 and visited upstream and downstream operations in the US and Angola and downstream sites in the US and UK.

In particular, we would highlight our reviews of key group risks, and associated risk management in: drilling and maintenance of wells; contractor management; non-operated joint ventures; fire and explosion risk at facilities and pipelines and shipping. These in-depth reviews have taken place during our regular meetings with executive management.

In the Upstream we have looked at risks and environmental issues arising in connection with, 'fracking' operations during a visit to our East Texas onshore operations. Other visits have been made to offshore Gulf of Mexico, Houston and Angola. In the Downstream, members of the committee have visited the company's paraxylene manufacturing facility in Texas, the Texas City refinery and the Buncefield terminal in the UK.

Duane Wilson's independent perspective of the company's response to the Baker Panel's recommendations following the fire and explosion at the Texas City refinery in 2005 was completed in May when he delivered his final report to SEEAC. We were pleased to engage him to work, in a global capacity, with the Downstream business. He continues to deliver reports to SEEAC when requested.

We were pleased to complete the engagement of Carl Sandlin in June to report independently to SEEAC on the implementation of the Bly Report recommendations. Carl Sandlin brings a vast amount of experience from his management of drilling operations during his career at ExxonMobil. He will also report to the committee on his observations of process safety culture in the Upstream.

We also welcomed Professor Dame Ann Dowling who brings deep experience in technology and engineering to the committee from February 2012.

Paul Anderson
Committee chair

Committee members

Paul Anderson – committee chair
Admiral Frank Bowman
Antony Burgmans
Cynthia Carroll
Sir William Castell (retired from the committee 12 April 2012)
Professor Dame Ann Dowling (joined the committee 3 February 2012)

Committee role and structure

The role of the SEEAC is to look at the processes adopted by BP's executive management to identify and mitigate significant non-financial risk, including monitoring process safety management, and receive assurance that they are appropriate in design and effective in implementation.

The committee met six times in 2012 including three joint meetings with the audit committee, at one of which the general auditor's report on internal control and risk management systems for the year was reviewed in preparation for the board's report to shareholders in the annual report. In that joint meeting the committees reviewed the internal audit programme for the year ahead to ensure both committees endorsed the coverage. The SEEAC and audit committee worked together, through their chairs and secretaries, to ensure that the agendas did not overlap or omit coverage of any key risks during the year.

In addition to the committee membership, SEEAC meetings were attended by the group chief executive, the executive vice president for safety and operational risk (S&OR) and the representatives from internal audit. The external auditor also attended some of the meetings (and was briefed on the other meetings by the chair and secretary to the committee). The group general counsel also attended meetings. The committee scheduled private sessions for members only (without the presence of executive management) at the conclusion of each meeting to discuss any issues arising and the quality of the meeting.

Committee processes

Information and advice

The committee receives specific reports from the business segments but also receives cross-business information from the functions. These include but are not limited to the safety and operational risk function, internal audit, group ethics and compliance and group security. The SEEAC can access any other independent advice and counsel if it requires, on an unrestricted basis.

Field trips and visits

The committee extended its coverage and number of visits this year by encouraging members to participate individually, or in groups, and report back to the next full meeting. Members have also presented at staff training events, such as Admiral Bowman addressing a meeting of the leadership of the global wells organization (GWO) in Florida in July and the committee chairman addressing senior leadership at the BP Academy at MIT (where Admiral Bowman also presented later in the year).

Upstream visits

In January the chairman and other members visited Houston to examine how GWO was monitoring and assuring the safety of drilling operations in the Gulf of Mexico. In May a committee member travelled offshore to the Thunder Horse platform in the Gulf of Mexico while other committee members visited drilling and 'fracking' operations in East Texas. In August a committee member travelled to Angola and met with leadership there to receive briefings on implementation of OMS and other safety-related issues.

Downstream visits

Considerable focus also continues to be placed on the Downstream and on the company's response to the BP US Refineries Independent Safety Review Panel recommendations. In January members of the committee visited the Texas City refinery, accompanied by Duane Wilson, to review progress in risk management systems and OMS implementation. During this visit, committee members also visited the nearby petrochemicals facility to observe the extent to which the BP US Refineries Independent Safety Review Panel recommendations had been implemented in the petrochemicals context. In December all members of the committee visited the Buncefield terminal in the UK and received briefings on OMS implementation as well as other safety-related improvements that had been made following the explosion at the neighbouring terminal in 2005.

2012 committee activities

Safety, operations and environment

The committee received regular reports from the S&OR function, including quarterly reports prepared for executive management on the group's health, safety and environmental performance and operational integrity. These included quarter-by-quarter measures of personal and process safety, environmental and regulatory compliance and audit findings. Operational risk and performance forms a large part of the committee's agenda. The S&OR function has intervention rights in all aspects of the group's technical and operational activities, and the committee sought evidence that this was working in practice. The committee's visits, as mentioned above, provided opportunities to discuss with local staff the interaction between line managers and embedded S&OR staff, and where change had occurred as a result.

During the year the committee received specific reports on the company's management of risks in shipping, wells, pipelines facilities, contractor management and non-operated joint ventures and also reviewed fire and explosion risk at facilities. The committee reviewed these risks, and risk management and mitigation, in depth with the relevant executive management.

When a fatality in the workforce occurs the committee reviews the incident in depth before reporting back to the board. The committee also reviewed specific incidents to understand root causes and actions being taken to prevent recurrence. There has been a particular focus on ensuring lessons learned are communicated widely across the company and not just within the business segment in which the incident occurred.

Upstream – independent perspective

Monitoring the company's progress in implementing the 26 recommendations in the Bly Report is a key task for the committee and it received regular updates, including written reports. The BP board identified and engaged Carl Sandlin to provide further oversight and assurance regarding the implementation of the Bly Report recommendations. He will track BP's progress in implementing the 26 recommendations from the company's internal investigation of the Deepwater Horizon accident and will independently assess the safety, health and environmental work of global drilling operations. As appropriate, Carl Sandlin will share his observations of BP's upstream process safety culture. He will give regular updates directly to the SEEAC and presented his initial work plan to SEEAC in October. He will meet with the committee at least twice a year.

Downstream – independent perspective

Since Duane Wilson's appointment by the board in 2007 as an independent expert, he has provided an objective assessment of BP's progress in implementing the recommendations of the BP US Refineries Independent Review Panel and assisted the company in improving process safety performance at BP's five US refineries. In his final report in May, Duane Wilson advised that he had observed continued progress in process safety performance at each visit he has made to the five refineries. At the same time, he also discussed work remaining to be completed and areas requiring special emphasis and noted that some aspects of implementing the Panel's 10 recommendations require ongoing activity and hence could never be complete, but he considers the company to have appropriate systems and processes to continue its work toward process safety leadership.

We were pleased to engage him beginning in May, to work with management on a worldwide basis to continue to embed process safety culture and learnings across the segment. In this new role he will meet with the committee at least twice a year.

TNK-BP

Each year the committee receives a report on the progress made in HSE and process safety at TNK-BP, noting however that formal oversight of their HSE performance and policies is exercised by TNK-BP's own HSE committee. It was reported that, whilst significant areas for improvement remained, TNK-BP had continued to make progress in addressing the main safety, ethical and environmental challenges confronting it since it was formed in 2003. The committee will continue to monitor progress regularly until such time as the company completes its exit from TNK-BP.

Committee evaluation

For its 2012 evaluation, the SEEAC again used a questionnaire administered by external consultants to examine the committee's performance and effectiveness. The committee responded to the same questions used in 2011 so that any change trends could be discerned. The topics covered included the balance of skills and experience among its membership, quality and timeliness of information the committee receives, the level of challenge between committee members and management and how well the committee communicates its activities and findings to the board.

The evaluation results were positive. In particular the committee members considered that the committee possessed the right mix of skills and background, had appropriate support and had received open and transparent briefings from management. The committee is keen to maintain and, if possible, increase the number of field trips it makes and to continue constructive and challenging engagement with management.

Gulf of Mexico committee

> "The committee oversaw the resolution of numerous matters in the past year; each was determined to be in the best interests of the company and its shareholders."

Chairman's introduction

The Gulf of Mexico committee met 23 times in 2012, with much of our focus on legal topics. The committee oversaw the resolution of numerous matters in the past year; each was determined to be in the best interests of the company and its shareholders and consistent with the board's overall strategy of reducing key uncertainties.

Settlements have been approved with the Plaintiffs' Steering Committee, with regard to private economic and property damages claims, as well as exposure-based medical claims stemming from the Deepwater Horizon accident; and the company reached resolutions with the Department of Justice and the Securities and Exchange Commission. The committee will be overseeing the company's compliance with government settlement agreements arising out of the Deepwater Horizon accident, in co-ordination with the other committees and the board as appropriate.

The committee has overseen the company's strategy for resolving claims not covered by the above settlements; its efforts to mitigate and monitor the effects of the spill; and actions to restore the group's reputation, particularly in the US. We have received regular briefings on the company's preparations for trial on the various civil matters, including the multi-district litigation in New Orleans.

Briefings on a broad range of topics have been provided to the committee by the leadership and counsel of the Gulf Coast Restoration Organization (GCRO). External counsel have also been invited to join some meetings.

The high frequency of our interactions has facilitated committee members' understanding of complex issues and interdependencies. I believe the committee maintains a rigorous approach to its work, providing effective oversight on behalf of the board. The report below summarizes the activities of the committee in 2012. The committee is well prepared to conduct its tasks over the coming year.

Ian Davis
Committee chair

Committee members

Ian Davis – committee chair
Paul Anderson
Admiral Frank Bowman (joined the committee 3 February 2012)
Sir William Castell (retired from the committee 12 April 2012)
George David

The Gulf of Mexico committee has cross-membership with both the SEEAC and the audit committee, helping to inform discussions of matters within the committee's remit. Membership of the Gulf of Mexico committee changed during 2012 and now includes three US-based non-executive directors.

All meetings during the course of the year have been attended by Lamar McKay, president and CEO of the GCRO in 2012, and Jack Lynch, chief counsel to the GCRO. The chairman, group chief executive and group general counsel join meetings whenever possible. Meetings are on occasion joined by others including members of the leadership team of the GCRO, as well as internal and external legal counsel.

Committee role and structure

The purpose of the committee is to provide non-executive oversight of the GCRO; to oversee the management and mitigation of legal and license-to-operate risks arising out of the Deepwater Horizon accident and the subsequent response; and to support efforts to rebuild trust in BP and BP's reputation, with a particular focus on the US.

The committee's work is fully integrated with that of the board on strategy, reputation and financial planning. The committee chairman provides verbal reports at board meetings, and all directors are invited, from time to time, to attend and observe committee meetings. Meeting minutes are sent to the board for review, and the board retains ultimate accountability for oversight of the group's response to the Deepwater Horizon accident.

The committee met 23 times in 2012, frequently by telephone and sometimes at very short notice.

During the course of the year the committee focused on the following tasks:

- Oversee and receive regular reports on work undertaken to complete the response and mitigate the effects of the oil spill in the Gulf of Mexico area.
- Oversee the legal strategy for litigation, investigations and administrative processes involving the group arising from the accident or its aftermath.
- Oversee the strategy for resolving claims, recognizing the independent role of first the Gulf Coast Claims Facility (GCCF) and more recently the Deepwater Horizon Court Supervised Settlement Program (DHCSSP).
- Oversee GCRO's plans for expenditures and investments on major projects or matters beyond those included within the above referenced independent claims administration processes.
- Oversee management's strategy and actions to restore the group's reputation in the US.

Committee processes

Information and advice

The committee receives its information from the leadership of the GCRO, internal personnel and external advisers. Privileged briefings are provided by the group general counsel and chief counsel to the GCRO, along with internal and external counsel who often participate in committee meetings. The committee received reports from internal audit on its reviews of the GCRO and related activities. The audit committee remains the primary forum for the monitoring of financial risk and audit matters relating to the GCRO. Safety risks relating to the GCRO's activities are monitored by the SEEAC.

Training and visits

The high frequency of meetings in 2012 facilitated the committee's understanding of key issues and numerous interdependencies in what at times has been a fast-moving external environment. Committee members have interacted with members of the GCRO leadership team, including at the two meetings of extended duration held in the US in 2012.

2012 committee activities

The committee's activities have included the following:

Legal

Privileged briefings continue to form a significant part of the committee's agenda, given the breadth and pace of legal developments. The committee oversaw the resolution of numerous matters in 2012; each was determined to be in the best interests of the company and its shareholders, and consistent with the overall strategy of reducing key uncertainties. These resolutions included the class-action settlements agreed with the Plaintiffs' Steering Committee (PSC), the criminal settlement with the Department of Justice, and the civil resolution with the Securities and Exchange Commission. The committee has overseen the company's continuing preparation for trial in the Multi-District Litigation in New Orleans, as well as a number of other litigation and administrative proceedings including the multi-district litigation in Houston and suspension and debarment proceedings led by the Environmental Protection Agency.

Remediation and restoration

The committee received regular updates on the progress of clean-up and remediation activities. The committee also monitored the Natural Research Damage (NRD) Assessment process, as well as discussions with Natural Resource Trustees on NRD matters including early restoration negotiations and projects.

Claims

The committee monitored claims processes, including those relating to state economic claims and the transition from the independently administered GCCF to the DHCSSP following the agreement of class-action settlements with the PSC[a]. Assessments of potential future claims for provisioning purposes are reviewed by the audit committee.

The committee recently undertook an evaluation of its effectiveness during 2012, as it has at the end of each year since its inception.

Nomination and chairman's committees

> I chair both the nomination and the chairman's committees. There is often an overlap between their work and this is reflected in their reports.

Nomination committee

Committee members

Carl-Henric Svanberg – committee chair
Antony Burgmans
Cynthia Carroll
Sir William Castell (retired from the committee 12 April 2012)
Ian Davis
Brendan Nelson (joined the committee April 2012)
Paul Anderson (joined the committee April 2012)

Andrew Shilston attends meetings of the committee in his capacity as senior independent director.

The committee met four times during 2012.

Committee role and structure

The committee identifies, evaluates and recommends candidates for the appointment or re-appointment as directors and for the appointment of the company secretary.

The committee keeps the mix of knowledge, skills and experience of the board under regular review (in consultation with the chairman's committee) to ensure an orderly succession of directors. The outside directorships and broader commitments of the non-executive directors are also monitored by the nomination committee.

The committee reviewed and confirmed these tasks during the year.

Committee activities

During the year the membership of the committee was reviewed. Brendan Nelson and Paul Anderson joined as members and Andrew Shilston was invited to attend as the senior independent director.

The committee reviewed the independence and roles of each of the directors prior to recommending them for re-election at the 2012 AGM. It also discussed the composition of the board and its committees in terms of service, skills and diversity.

Professor Dame Ann Dowling joined the BP board on 3 February 2012 following a recommendation from the committee. The committee had retained the services of external advisors Odgers to assist with the identification of potential candidates for this appointment.

During the year the committee considered the skills and experience required for board members against the strategic direction of the company at two of its meetings. The committee also considered the skills of the current directors and were satisfied that the board had the appropriate balance of skills and experience.

The committee discussed the board's publicly stated aspirations for diversity and agreed metrics as required by the UK Corporate Governance Code. The metrics agreed by the committee on behalf of the board are:

- The absolute number of male and female board members (to measure the board's progress in gender diversity).
- The absolute number of different nationalities on the board (as a measurement of geographic diversity on the board).

The committee agreed that data on these two objectives will be included in the board performance report in the *BP Annual Report and Form 20-F* and reported against in future years (see page 113 for 2012 board diversity data).

The committee considered the position of candidates identified as potential non-executive directors and based on the description of the required skills and experience agreed to commence searches for appropriate candidates for the medium term.

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[a] See Plaintiffs' Steering Committee settlements on page 60 and Financial statements – Note 36 on page 236 for further information.

The committee discussed the time commitment for non-executive directors. The letters of appointment for BP non-executive directors do not state a time commitment and this is explained annually as part of the compliance statement with the UK Corporate Governance Code. The committee took the view that it would be artificial to set such a metric. The experience of the board over the past three years was that directors had been required to spend such time as was necessary on the business of the company. Whilst it was hoped that the work of the board and its committees would not be as intense in coming years, it was important that directors were able to respond promptly. The committee would keep under review the attendance and commitment of board members.

The committee reviewed the periods of service of the non-executive directors and noted the substantial refreshment of the board over the past three years. The committee was strongly of the view that continuity of service and corporate memory was important to the board's working and accordingly agreed with Antony Burgmans that he would remain as a director for a further three-year period. In coming to this view the committee considered his clarity of thought and his approach in evaluating the events of the last few years and concluded that he remained independent in his judgement. The committee further noted that since 2004 all directors on the board had been subject to annual re-election.

Sir William Castell stood down from the board and as senior independent director in April 2012. The committee discussed Sir William's successor as SID on two occasions and made recommendations to the chairman's committee on appropriate candidates.

Committee evaluation

At the end of the year, the committee undertook an annual examination of its effectiveness and performance, using a questionnaire. As part of its evaluation, the committee considered its role and its task for the year. The evaluation concluded that the committee had worked well and had improved its focus on diversity. Going forward the committee wishes to focus on agenda setting and papers with a view to improving time management and workload.

Chairman's committee

Committee members

Carl-Henric Svanberg – committee chair
Paul Anderson
Admiral Frank Bowman
Antony Burgmans
Cynthia Carroll
Sir William Castell (retired from the committee in April 2012)
George David
Ian Davis
Professor Dame Ann Dowling (joined the committee February 2012)
Brendan Nelson
Phuthuma Nhleko
Andrew Shilston (joined the committee January 2012)

The committee met eight times during 2012.

Committee role and structure

The committee is comprised of the chairman and all the non-executive directors.

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

The committee held private discussions between the non-executive directors during the year on a number of key issues for BP.

The committee carried out the evaluation of the chairman and the chief executive early in the year. The committee also set the parameters for these evaluations to take place in early 2013.

The committee received a recommendation from the nomination committee for the appointment of a senior independent director to replace Sir William Castell who was to stand down in April 2012. The committee agreed to recommend to the board that Andrew Shilston be appointed the SID; however Antony Burgmans, as longest serving non-executive director would act as the focal point for internal board matters and would lead the evaluation of the chairman.

The committee reviewed the membership of the board committees and agreed certain modifications.

In addition, during 2012 the committee considered:

- The views of some shareholders as relayed by the chairman and the senior independent director.
- On several occasions, with the chief executive officer, the strategic direction of the group.
- Again with the chief executive officer, the composition and evolution of the top management team and the implications of the implementation of the functional organization.
- The information available to the board.

UK Corporate Governance Code compliance

BP complied throughout 2012 with the provisions of the UK Corporate Governance Code, except in the following aspects:

B.3.2 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 demands of business and other events. 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.

D.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. We believe this wider process lets all board members discuss and approve the chairman's remuneration (rather than solely the members of the remuneration committee).

E.2.4 Printed copies of the *BP Annual Report and Form 20-F 2011* completed mailing outside of the Governance Code period of 20 working days before the AGM (but within the UK Companies Act notice period). This was due to printing being delayed following revisions to the report in view of the class action settlements agreed with the Plaintiffs' Steering Committee (PSC) on 3 March 2012.

Directors' remuneration report

Our commitment to both shareholder interests and executive engagement continues, and we are confident that our approach to executive pay aligns well with the recovery of BP's business.

Chairman's introduction

> The continuity of our pay structure provides a relatively simple, performance-based system tied directly to strategy.

Dear shareholder

BP made many further positive steps in its recovery journey during 2012. The remuneration committee recognizes the patience of investors during this period since the 2010 Deepwater Horizon accident. Equally we recognize the persistence of our executives in embedding safe and effective operations deeply into the fabric of the company while systematically restoring value. Progress is being made, reflecting a clear strategy and disciplined execution.

Our remuneration system for executive directors is tied closely to this progress. The company's strategy forms the basis for an annual plan and the measures and targets used for both annual and long-term variable pay. Variable pay, based on performance, makes up the vast majority of total potential remuneration for executive directors, and of that, most is long-term, reflecting the nature of BP's business and providing strong alignment with shareholders.

Our process for determining pay is both rigorous and independent. I have met with a number of our key shareholders again this year to understand their perspectives. We seek to reflect shareholders' interests as well as to fairly reward the achievements of our executives, recognizing the contentious nature of top executive pay while ensuring competitiveness for our talented leadership. We believe informed, balanced judgement, and transparency of our decisions is vital. These principles continue to guide the committee's operation and have led to large variability in total remuneration for our executive directors over the past decade, reflecting the underlying performance of the company.

2012 outcomes

The outcomes of the various plans that make up 2012 total remuneration for executive directors are summarized in the table on page 130.

Annual bonus

Overall group performance was assessed at just below target. Annual bonus results were based on performance assessed against targets established at the start of the year and reflected the strategic priorities of safety and operational risk management, rebuilding trust and restoring value.

Safety and risk management results, accounting for 30% of bonus, were generally at or better than plan, with significant improvement and high standards in both loss of primary containment and process safety tier 1 incidents – both key indicators of process safety.

Rebuilding trust accounted for 20% of bonus, and the company continued to make important gains as measured by independent surveys.

Restoring value metrics accounted for 50% of bonus with somewhat mixed results. Upstream major project delivery was on target, and divestment targets were exceeded but operating cash flow, underlying replacement cost profit and total cash costs did not achieve plan targets.

Performance shares

No shares vested in the 2010-2012 share element. Performance measures for this plan related to total shareholder return, production, net income, and downstream profitability – all relative to the other oil majors. As the starting point for these metrics was prior to the Deepwater Horizon accident, performance failed to meet the level required for vesting.

Other elements

Salaries were increased 3% mid-year for Bob Dudley, Iain Conn and Dr Byron Grote. The deferred bonus component was first introduced following shareholder approval in 2010, and so no plan is yet eligible for vesting and will not be until early 2014. Pension increases reflect the application of relevant plan rules. As Bob Dudley's defined benefit pension is based on three-year average remuneration, its increased value reflects a catching up with his promotion, first to the board in 2009 and secondly to group chief executive in 2010. Similarly, Dr Brian Gilvary's pension increase reflects his promotion to chief financial officer at the start of 2012.

2013 policy

For 2013 our overall policy for executive directors will remain largely unchanged, and is summarized on page 136. The continuity of our pay structure comprising salary, annual bonus, deferred bonus, performance shares, and pension, provides a relatively simple, performance-based system tied directly to strategy. Salaries will be reviewed mid-year taking into consideration both external and internal relativities. Annual bonus will operate in the same way as last year but the metrics have evolved slightly to reflect annual plan priorities and with increased weight on restoring value. Performance shares follow the same format as last year with minor change in the metrics to align with strategy.

Report format

The UK government has issued draft regulations on revised reporting for directors' remuneration which are expected to be finalized later this year. We support many of the changes planned and have incorporated these into the current report to the extent we believe is appropriate while still complying with current regulations.

We hope that you find this report both informative and reassuring. Our commitment to both shareholder interests and executive engagement continues, and we are confident that our approach to executive pay aligns well with the recovery of BP's business.

Antony Burgmans KBE
Chairman of the remuneration committee
6 March 2013

Remuneration – the big picture

The remuneration policy for executive directors and the decisions of the remuneration committee have, for many years, been guided by key principles:

Linked to strategy	→	A substantial portion of executive remuneration should be linked to success in implementing the company's business strategy.
Performance related	→	The major part of total remuneration should vary with performance, with the largest elements share based, further aligning interests with shareholders.
Long-term based	→	The structure of pay should reflect the long-term nature of BP's business and the significance of safety and environmental risks.
Informed judgement	→	There should be both quantitative and qualitative assessments of performance with the committee making an informed judgement within a framework approved by shareholders.
Shareholder engagement	→	The remuneration committee will actively seek to understand shareholder preferences and be transparent in explaining its remuneration policy and practices.
Fair treatment	→	The total quantum of pay should take account of both external market and company conditions to achieve a balanced 'fair' outcome.

As reflected in the diagram below, the company's strategy forms the core from which key performance indicators are established. The total remuneration for executive directors is then tied to this via the four elements of total remuneration identified in the diagram below. Three of the four vary with performance and the majority of their remuneration is long term. For ease of reference page numbers in the report have been identified for each element where further detail can be found.

Annual bonus

2012 bonus outcomes
see page 132
- Overall bonus result 97% of target for group results

2013 policy
see page 138
- Unchanged from 2012
- 30% based on safety and operational risk
- 70% based on value

- Annual plan developed from strategy and 10-point plan
- Bonus metrics reflect key aspects of annual plan
- Meeting plan results in on-target bonus

Deferred bonus

2012 deferred bonus outcomes
see page 133
- No vesting as first plan matures in 2014

2013 policy
see page 139
- Unchanged from 2012

- All deferred and matched shares are subject to safety and environmental sustainability performance over the three-year deferral period

Salary and pension

2012 salary outcomes
see page 131
- Salaries increased by up to 3% in 2012

2012 pension outcomes
see page 133
- Pension increases in line with plan rules and mainly due to promotions

2013 policy
see pages 137 and 141
- Unchanged from 2012

- Salaries reviewed annually taking account of both internal and external comparators
- Pensions follow country norms and executive directors participate in regular home-country plans

Performance shares

2010-2012 plan outcomes
see page 133
- No shares vested in 2010-2012 plan

2013-2015 plan policy
see page 140
- Unchanged from 2012

- Performance measures reflect strategy and KPIs
- Three-year performance period followed by three-year retention period

2012 total remuneration outcomes

Overview

Summary of remuneration of executive directors in 2012 (audited)

	Bob Dudley thousand		Iain Conn thousand		Dr Brian Gilvary thousand		Dr Byron Grote thousand	
Annual remuneration	**2012**	2011	**2012**	2011	**2012**	2011[a]	**2012**	2011
Salary	**$1,726**	$1,700	**£741**	£720	**£690**	n/a	**$1,464**	$1,426
Cash bonus[b]	**$837**	$850	**£374**	£396	**£366**	n/a	**$710**	$713
Other emoluments	**$110**	$66	**£39**	£35	**£13**	n/a	**$15**	$15
Total	**$2,673**	$2,616	**£1,154**	£1,151	**£1,069**	n/a	**$2,189**	$2,154
Vested equity								
Deferred bonus and match	**$0**	$0	**£0**	£0	**£0**	n/a	**$0**	$0
Performance shares[c]	**$0**	$788	**£666[d]**	£743	**£299[d]**	n/a	**$0**	$1,450
Total	**$0**	$788	**£666**	£743	**£299**	n/a	**$0**	$1,450
Total remuneration	**$2,673**	$3,404	**£1,820**	£1,894	**£1,368**	n/a	**$2,189**	$3,604
Pension								
Pension value increase[e]	**$7,317**	$4,908	**£940**	£1,209	**£2,132**	n/a	**$987**	$1,750
Cash in lieu of future accrual[f]	**n/a**	n/a	**£259**	£192	**£242**	n/a	**n/a**	n/a
Total including pension	**$9,990**	$8,312	**£3,019**	£3,295	**£3,742**	n/a	**$3,176**	$5,354

Amounts shown are in the currency received by executive directors. Annual bonuses are shown in the year they were earned.

[a] Dr Brian Gilvary joined the board on 1 January 2012.

[b] This reflects the amount of total overall bonus paid in cash with the deferred portion as set out in the conditional equity table below.

[c] Represents vesting of shares made at the end of the relevant performance period based on performance achieved under rules of the plan and includes re-invested dividends on the shares vested.

[d] There was no vesting under the 2010-2012 performance share element. The shares that vested for Iain Conn pertained to a separate restricted award made in 2008 and those for Dr Brian Gilvary to an award granted prior to joining the board. The market price of ordinary shares on respective vesting dates of 7 February 2013 and 15 January 2013 was £4.58.

[e] Represents the increase in transfer value calculated for defined benefit plans. Increases for Bob Dudley and Dr Brian Gilvary reflect their promotions as per applicable rules.

[f] As for all employees affected by UK pension tax limits and who wished to remain within these limits, with effect from April 2011, Iain Conn and Dr Brian Gilvary received a cash supplement of 35% of basic salary in lieu of future service pension accrual.

Conditional equity – to vest in future years, subject to performance

		Bob Dudley		Iain Conn		Dr Brian Gilvary		Dr Byron Grote	
Deferred bonus in respect of bonus year[a]		**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011
Mandatory deferral	Value (thousand)	**$837**	$850	**£374**	£396	**£366**	n/a	**$710**	$713
Voluntary deferral	Value (thousand)	**$837**	$850	**£374**	£396	**£366**	n/a	**$710**	$713
Total deferral converted to shares	Shares	**229,380**	218,412	**161,296**	161,304	**157,630**	n/a	**194,556**	183,276
Total matching shares	Shares	**229,380**	218,412	**161,296**	161,304	**157,630**	n/a	**194,556**	183,276
Vesting date		**Feb 2016**	Feb 2015	**Feb 2016**	Feb 2015	**Feb 2016**	Feb 2015	**Feb 2016**	Feb 2015
Performance shares		**2012-2014**	2011-2013	**2012-2014**	2011-2013	**2012-2014**	2011-2013	**2012-2014**	2011-2013
Potential maximum shares		**1,343,712**	1,330,332	**660,633**	623,025	**624,434**	n/a	**828,936**	785,394
Vesting date		**Feb 2015**	Feb 2014	**Feb 2015**	Feb 2014	**Feb 2015**	Feb 2014	**Feb 2015**	Feb 2014

[a] The number of deferred shares is calculated using the three-day average share price following the full-year result announcement which was £4.91/share and $46.70/ADS in February 2012 and £4.64/share and $43.78/ADS in February 2013. Both deferred and matched shares are subject to a safety and environmental hurdle over the three-year deferral period.

Non-executive directors in 2012 (audited)

		£ thousand
	2012	2011
Carl-Henric Svanberg	**750**	750
Paul Anderson	**149**	128
Admiral Frank Bowman	**126**	120
Antony Burgmans	**120**	100
Cynthia Carroll	**98**	85
George David[a]	**135**	128
Ian Davis	**128**	160
Professor Dame Ann Dowling[b c]	**97**	–
Brendan Nelson	**119**	103
Phuthuma Nhleko	**123**	113
Andrew Shilston[d]	**125**	–
Director leaving the board in 2012		
Sir William Castell[e]	**42**	168

[a] In addition, George David received £28,000 for chairing the BP technology advisory council.

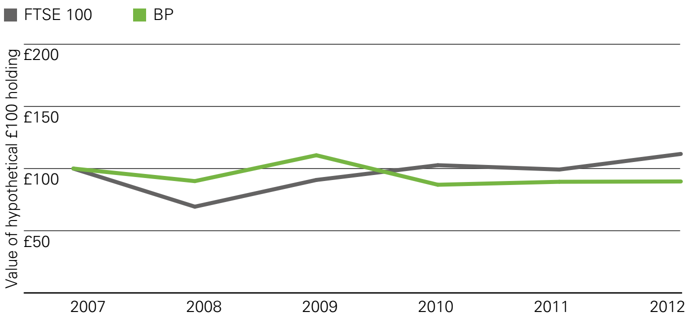
[b] Appointed on 3 February 2012.

[c] In addition, Professor Dowling received £4,166 for her membership of the BP technology advisory council.

[d] Appointed 1 January 2012 and became senior independent director in April 2012.

[e] Retired from the board in April 2012.

Historical TSR performance



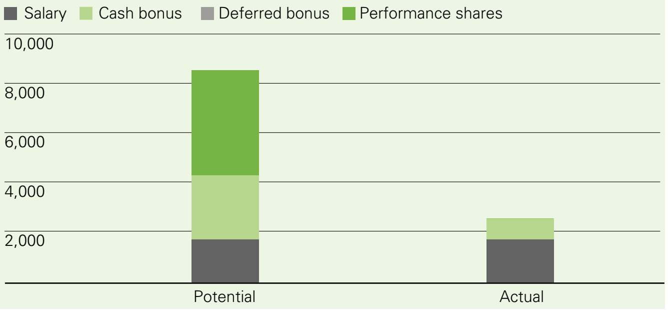
This graph shows the growth in value of a hypothetical £100 holding in BP p.l.c. ordinary shares over five years, relative to the FTSE 100 Index (of which the company is a constituent). The values of the hypothetical £100 holdings at the end of the five-year period were £89.60 and £111.79 respectively.

2012 total remuneration in more depth

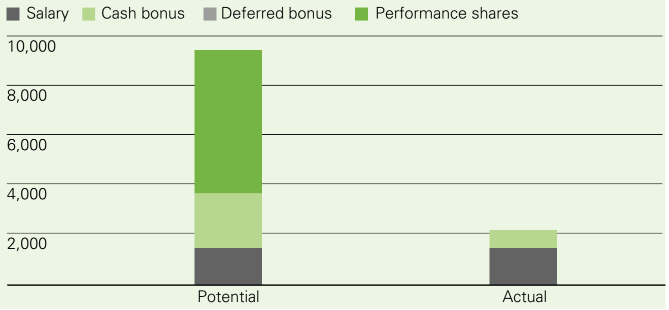
This section contains detail on executive directors' remuneration including salary, annual bonus and deferred bonus relating to 2012 and performance shares for 2010-2012.

The charts below summarize the actual total direct remuneration outcome of 2012 for each of the executive directors compared to the potential that would have been realised if variable plans had paid out at maximum.

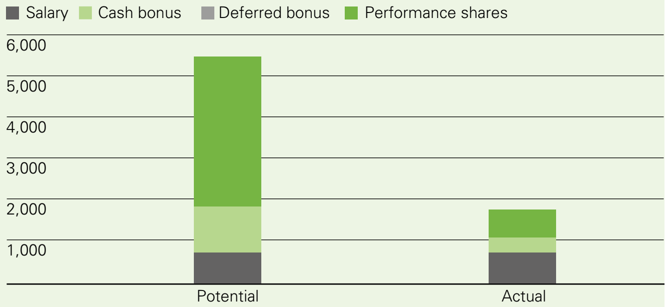
Bob Dudley ($ thousand)



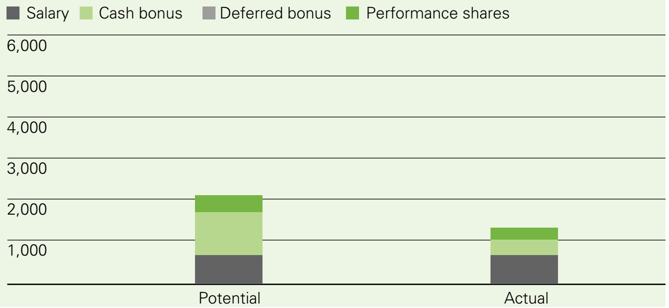
Dr Byron Grote ($ thousand)



Iain Conn (£ thousand)



Dr Brian Gilvary (£ thousand)



The definitions for both the charts above and the summary table on the page opposite reflect those that are contained in the draft remuneration reporting regulations proposed by the UK government's Department for Business Innovation and Skills (BIS). In summary:

- **Salary** – actual salary received during 2012 both for actual and potential.
- **Cash bonus** – actual cash bonus received for 2012 compared to potential cash bonus if maximum of 225% of salary had been achieved and one-third mandatory deferral applied.
- **Deferred bonus** – as per the draft regulations, this reflects deferred bonus from previous years that vested in 2012. The first potential vesting will be in 2014.
- **Performance shares** – shows the actual value of the performance shares that vested at the end of 2012. The potential shows the value that would have been attained if all shares had vested. The same share price was used for both calculations. For Iain Conn, the information also reflects restricted shares awarded in 2008, and for Dr Brian Gilvary an award prior to him joining the board. Further detail can be found on page 133.

Salary – 2012 outcomes

Salaries were reviewed in May 2012 relative to other oil majors, other large UK and Europe-based international companies and key US companies. The committee also considered the level of pay increases for executives below board level, as well as different employee groups across the business.

Based on this review, salaries were increased by 3% for Bob Dudley (to $1,751,000), Iain Conn (to £752,000) and Dr Byron Grote (to $1,485,000) effective 1 July 2012. Dr Brian Gilvary's salary of £690,000, which had been set on his appointment on 1 January, was unchanged.

Annual bonus – 2012 outcomes

Framework

All executive directors were eligible for an overall annual bonus, including deferral, of 150% of salary at target and a maximum of 225% of salary. Bob Dudley's annual bonus was based entirely on group results and Iain Conn's, Dr Brian Gilvary's, and Dr Byron Grote's were based 70% on group results and 30% on their respective segment or function.

Measures and targets for the annual bonus were set at the start of the year and were derived from the company's annual plan which, in turn, reflected its strategy and key performance indicators. Measures were grouped under the three dominant strategy themes of safety and operational risk management (S&OR), rebuilding trust, and restoring value. Targets were set so that meeting plan equates to on-target bonus.

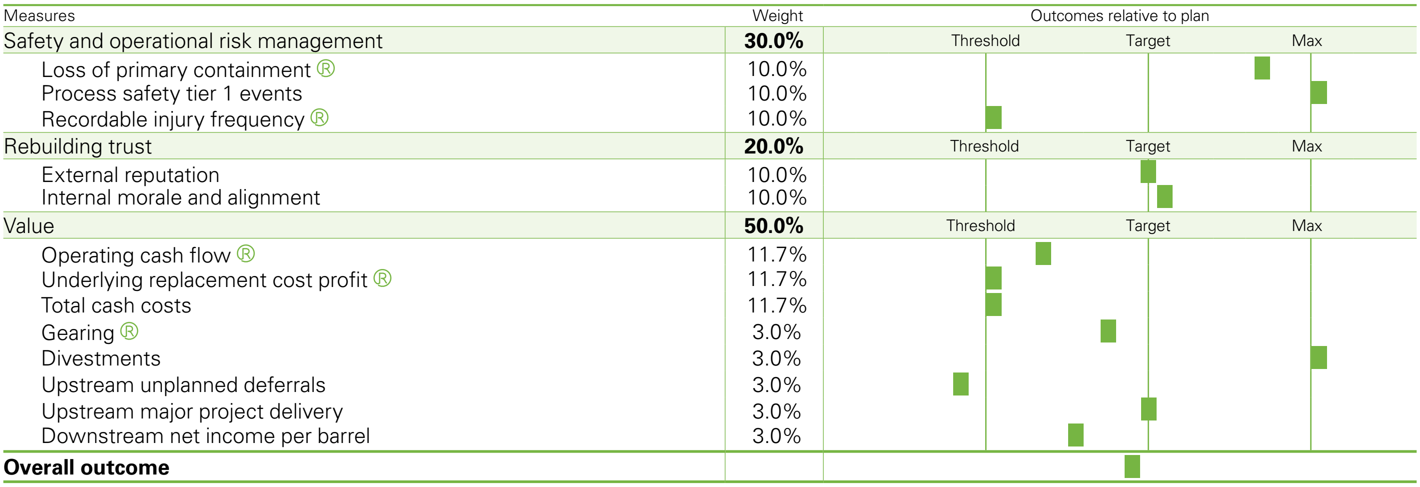
At group level, S&OR was set to account for 30% of total bonus and included targets for loss of primary containment, process safety tier 1 events, and recordable injury frequency. Rebuilding trust was weighted at 20% of the total and included external reputation, and internal morale and engagement. Both components were assessed via results of surveys. Finally, restoring value was set to account for 50% of total bonus and included targets for operating cash flow, underlying replacement cost profit, total cash costs, gearing, divestments, upstream unplanned deferrals, upstream major project delivery, and Downstream net income per barrel.

Additional measures and targets were set for Iain Conn's, Dr Brian Gilvary's and Dr Byron Grote's respective segments or functions. These focused on safety, operating efficiency and profitability for the Downstream segment and key strategic priorities and outcomes for the functions.

As well as the specific measures set out, the committee considers any other results or factors it deems relevant and applies its judgement in determining final bonus outcomes.

Outcomes

2012 annual bonus outcomes



Measures	Weight
Safety and operational risk management	**30.0%**
Loss of primary containment ®	10.0%
Process safety tier 1 events	10.0%
Recordable injury frequency ®	10.0%
Rebuilding trust	**20.0%**
External reputation	10.0%
Internal morale and alignment	10.0%
Value	**50.0%**
Operating cash flow ®	11.7%
Underlying replacement cost profit ®	11.7%
Total cash costs	11.7%
Gearing ®	3.0%
Divestments	3.0%
Upstream unplanned deferrals	3.0%
Upstream major project delivery	3.0%
Downstream net income per barrel	3.0%
Overall outcome	

® See pages 28-29 for how our bonus measures for 2012 and 2013 are directly linked to business KPIs.

Performance outcomes for the year are summarized in the table above, with a more detailed explanation following.

Safety and operational risk management performance was strong. Loss of primary containment showed a 19% improvement and process safety tier 1 events dropped by 42% over last year. Both metrics are important indicators of process safety performance. Recordable injury frequency (RIF) included, for the first time, the biofuels business acquired last year. Demanding targets had been set to bring overall safety standards in the biofuels business to a level consistent with the rest of the company. In the end, performance in that business improved significantly but failed to meet the targets set and this meant that overall company targets were missed. Excluding biofuels, RIF performance was strong and improved over 2012.

Rebuilding trust showed overall satisfactory results. In terms of external reputation, independent external surveys showed important progress towards rebuilding reputation in both the US and UK. Internally, the 'pulse survey' reflected good and improving overall engagement with 11 of 12 areas of specific ongoing monitoring all showing like-for-like better results than last year.

Performance related to restoring value was somewhat mixed, in part reflecting the priority throughout the company's business of continuing to embed safe and effective operations. Operating cash flow, underlying replacement cost profit and total cash costs all came in between threshold and target. Divestment targets were far exceeded and gearing just below target. Upstream major project delivery was on target but unplanned deferrals missed threshold levels. Downstream net income per barrel also achieved between threshold and target.

Based on these results, the formulaic outcome for group results was 97% of target. The remuneration committee concluded that this represented fairly the overall performance of the business during the year, and confirmed the score for group purposes. Bob Dudley's total overall bonus therefore was 97% of target, resulting in 146% of salary. The same score was applied to each of the other executive directors for 70% of their bonus that was determined by group results. Combined with the results for their respective segments and functions the total overall scores were 101% of target for Iain Conn, 106% for Dr Brian Gilvary and 97% for Dr Byron Grote.

Of the total bonuses referred to above, one-third is paid in cash, one-third is deferred on a mandatory basis, and one-third is paid either in cash or voluntarily deferred at the individual's discretion. As all four executive directors chose to participate in the voluntary deferral, amounts received by each of the individuals are shown below (as well as in the total remuneration summary chart on page 130).

	Cash bonus thousand	Mandatory deferral thousand	Voluntary deferral thousand
Bob Dudley	$837	$837	$837
Iain Conn	£374	£374	£374
Dr Brian Gilvary	£366	£366	£366
Dr Byron Grote	$710	$710	$710

Deferred bonus – 2012 outcomes

Framework

One-third of the total bonus awarded to the executive directors is deferred into shares on a mandatory basis under the terms of the deferred bonus element. Deferred shares are matched on a one-for-one basis and both deferred and matched shares vest after three years contingent on an assessment of safety and environmental sustainability over the three-year deferral period.

Individuals may elect to defer an additional one-third of total bonus into shares on the same basis and subject to the same contingency as the mandatory deferral.

Outcomes

No plans matured in 2012 for executive directors. The deferred element for executive directors was approved by shareholders and implemented in 2010. Therefore the first plan will be eligible to vest in early 2014 following the three-year deferral period and contingent on the assessment of safety and environmental sustainability over the same period.

Dr Brian Gilvary participated in a deferred bonus plan prior to his appointment as an executive director and details of this are provided in the table on page 144.

Performance shares – 2012 outcomes

Framework

Performance shares were awarded to each executive director in early 2010 with vesting after three years dependent on performance relative to measures reflecting the company's strategic priorities at the time. For the 2010-2012 plan, vesting was based one-third on total shareholder return (TSR) compared to the other oil majors, and two-thirds on a balanced scorecard of underlying performance factors compared to the same peers. The underlying performance factors were production growth, Downstream profitability, and underlying net income growth. The peer group includes ExxonMobil, Shell, Chevron, Total and ConocoPhillips. Vesting was set at 100%, 70% and 35% for performance equivalent to first, second and third rank respectively and none for fourth or fifth place of the peer group, with BP's position interpolated amongst them.

Outcomes

As the starting point for all measures was before the Deepwater Horizon accident, the impact of this continues to be dominant. Results for all measures were below the third place required and so no shares vested. The resulting shares and value of the vesting for each individual are shown to the right (as well as in the total remuneration summary chart on page 130).

	Original award	Shares vested (including dividends)	Value of vested shares thousand
Bob Dudley			
performance shares	581,082	0	$0
Iain Conn			
performance shares	656,813	0	£0
restricted shares	133,452	145,489	£666
Dr Byron Grote			
performance shares	801,894	0	$0
Dr Brian Gilvary	82,500	65,414	£299

Iain Conn was awarded restricted shares in early 2008 subject to continued service and satisfactory performance. The first tranche of these vested in February 2011 and the second in February 2013. This final tranche has been included in this year's disclosure for completeness. Dr Brian Gilvary's vesting reflects awards granted prior to him joining the board under equivalent plans below board level which vest at the same time as the executive director performance shares.

Pensions – 2012 outcomes

Framework

Executive directors are eligible to participate in regular company pension schemes that apply in their home countries which follow national norms in terms of structure and levels.

Bob Dudley and Dr Byron Grote both participate in the US plan and Iain Conn and Dr Brian Gilvary in the UK plan. Full details on these plans are set out in the policy section of this report (page 141).

Outcomes

The table below sets out the change in pension for 2012. This table follows the format required by current UK reporting regulations rather than the draft regulations that are expected to come into effect in late 2013.

Bob Dudley's pension increase is largely due to his promotion to group chief executive in late 2010. Since his pension is based on three-year average salary and bonus, the impact of a promotion takes a number of years to be fully reflected in his pension. Dr Brian Gilvary's pension, based on final salary, also shows a significant increase due to his promotion in January 2012.

Under the draft regulations, the disclosure of total pension includes any cash in lieu of additional accrual that is paid to individuals in the UK scheme who have exceeded the annual allowance or lifetime allowance under UK regulations. Both Iain Conn and Dr Brian Gilvary fall into this category and in 2012 received cash supplements of 35% of salary in lieu of future service accrual.

In terms of calculating the increase in pension value both a column on 20 times additional pension earned during the year as per the draft regulations, as well as the transfer value increase as currently stipulated have been included in the table below. The summary table on page 130 uses the increase in transfer value (last column below) to which the cash supplements are separately identified.

Pensions (audited)

thousand

	Service at 31 Dec 2012	Accrued pension entitlement at 31 Dec 2012	A:Additional pension earned during the year ended 31 Dec 2012[a]	B:Transfer value of accrued benefit at 31 Dec 2011[b]	C:Transfer value of accrued benefit at 31 Dec 2012[b]	Amount of 20 times A	Amount of C-B less contributions made by the director in 2012
Bob Dudley (US)	33 years	$1,381	$433	$15,244	$22,561	$8,660	$7,317
Iain Conn (UK)	27 years	£316	£9	£6,582	£7,522	£180	£940
Dr Brian Gilvary (UK)	26 years	£317	£64	£5,486	£7,618	£1,280	£2,132
Dr Byron Grote (US)	33 years	$1,388	$60	$18,251	$19,238	$1,200	$987

[a] Additional pension earned during the year includes an inflation increase of 4.8% for UK directors and 1.7% for US directors.

[b] Transfer values have been calculated in accordance with guidance issued by the actuarial profession.

Remuneration committee

The committee was made up of the following independent non-executive directors:

Antony Burgmans – chairman
George David
Ian Davis
Professor Dame Anne Dowling (appointed July 2012)
Carl-Henric Svanberg normally attends the meetings.

Tasks

The committee's tasks are formally set out in the board governance principles as follows:

- 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 schemes of which the executive directors are members.
- To nominate, on behalf of the board, any trustees (or directors of corporate trustees) of such schemes.
- To review and approve the policies and actions 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 of the board.

Committee activities

During the year, the committee met five times. Key discussions and decision items are shown in the table below.

The committee again undertook an evaluation of its operations using an external questionnaire administered by an external consultant. The committee discussed the findings at its January 2013 meeting. Almost all processes were rated as good to excellent in the report and in discussion the committee identified a number of areas for inclusion in 2013 agendas.

Remuneration committee 2012 meetings

	Feb	May	Jul	Sep	Dec
Strategy and policy					
Directors' remuneration report for 2012 AGM	🟩				
Directors' remuneration report vote outcome		🟩			
Remuneration policy		🟩			
Committee operation		🟩			
Salary review					
Executive directors		🟩			
Executive team and leadership group	🟩				
Annual bonus					
Assess performance	🟩		🟩		
Determine bonus for 2011	🟩				
Review measures for 2013				🟩	
Agree measures and targets for 2013					🟩
Long-term equity plans					
Assess performance	🟩		🟩		
Determine vesting of 2009-2011 plans	🟩				
Agree awards for 2012-2014 plans	🟩				
Review measures for 2013-2015 plans				🟩	
Agree measures and targets for 2013-2015 plans					🟩
Other items					
Review chairman's fees					🟩
Other issues as required	🟩	🟩	🟩	🟩	🟩

Independence

The committee operates with a high level of independence. The board considers all committee members to be independent (see page 112) with no personal financial interest, other than as shareholders, in the committee's decisions.

The group chief executive is consulted on matters relating to the other executive directors and senior executives who report to him and on matters relating to the performance of the company; neither he nor the chairman of the board participate in decisions on their own remuneration. Both the company's head of human resources and head of group reward attend relevant sections of meetings to ensure appropriate input on matters related to executives below board level.

Gerrit Aronson, an independent consultant, is the committee's independent adviser as well as secretary. He is engaged directly by the committee and not by executive management. Advice is also received from the company secretary, who reports to the chairman of the board; and from other external advisers appointed by the committee for specialist advice and services on particular remuneration matters. In 2012 the committee continued to engage Towers Watson as its principal external adviser, primarily for market information. Freshfields Bruckhaus Deringer LLP provided legal advice on specific matters to the committee. Both firms provide other advice in their respective areas to the group. The independence of the advice is periodically reviewed by David Jackson, the company secretary to ensure it meets a high standard.

Shareholder engagement

The committee values its dialogue with major shareholders on remuneration matters. During the year the committee's chairman and the committee's independent adviser personally met with key shareholders holding around 20% of the company's shares to ascertain their views and discuss important aspects of the committee's policy. They also met key proxy advisers to similarly engage. This engagement provides the committee with an important direct perspective of shareholder interests and, along with the vote at the AGM on the directors' remuneration report, is considered when making decisions.

Directors' interests

The figures below indicate and include all the beneficial and non-beneficial interests of each director of the company in shares of BP (or calculated equivalents) that have been disclosed to the company under the Disclosure and Transparency Rules as at the applicable dates.

Current directors	Ordinary shares or equivalents at 1 Jan 2012	Ordinary shares or equivalents at 31 Dec 2012	Change from 31 Dec 2012 to 25 Feb 2013	Ordinary shares or equivalents total at 25 Feb 2013
Carl-Henric Svanberg	942,979	988,077	–	988,077
Bob Dudley	337,301[a]	346,008[a]	–	346,008[a]
Paul Anderson	6,000[a]	6,000[a]	24,000[a]	30,000[a]
Admiral Frank Bowman	12,720[a]	16,320[a]	–	16,320[a]
Antony Burgmans	10,156	10,156	–	10,156
Cynthia Carroll	10,500[a]	10,500[a]	–	10,500[a]
Iain Conn	425,169[b]	509,729[b]	70,423	580,152[b]
George David	579,000[a]	579,000[a]	–	579,000[a]
Ian Davis	10,391	10,866	–	10,866
Dr Brian Gilvary	236,029	331,977	77,267	409,244
Dr Byron Grote	1,394,819[c]	1,512,616[c]	–	1,512,616[c]
Brendan Nelson	11,040	11,040	–	11,040
Phuthuma Nhleko	–	–	–	–
Andrew Shilston	–	15,000	–	15,000
Directors joining the board	On appointment			
Professor Dame Ann Dowling	–[d]	11,630	–	11,630
Directors leaving the board	At 1 Jan 2012	At resignation/ retirement		
Sir William Castell	82,500	82,500[e]	–	–

[a] Held as ADSs.
[b] Includes 48,024 shares held as ADSs.
[c] Held as ADSs, except for 94 shares held as ordinary shares.
[d] On appointment at 3 February 2012.
[e] On retirement at 12 April 2012.

The table below shows both the performance shares and the deferred bonus element awarded under the BP Executive Directors' Incentive Plan (EDIP). 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. Additional details regarding the performance shares and deferred bonus elements of the EDIP awarded can be found on pages 143 and 144.

Current directors	Performance shares at 1 Jan 2012	Performance shares at 31 Dec 2012	Change from 31 Dec 2012 to 25 Feb 2013	Performance shares total at 25 Feb 2013
Bob Dudley[a]	2,451,048	3,691,950	1,270,710	4,962,660
Iain Conn	2,103,422	2,305,847	365,314	2,671,161
Dr Brian Gilvary[b]	67,500	669,434	934,620	1,604,054
Dr Byron Grote[a]	2,686,632	2,889,192	446,430	3,335,622

[a] Held as ADSs.
[b] This includes conditionally awarded shares made under the Competitive Performance Plan prior to his appointment as a director. The vesting of these shares is subject to performance conditions.

At 25 February 2013, the following directors of BP p.l.c. held the numbers of options under the BP group share option schemes for ordinary shares or their calculated equivalent, and the number of restricted shares as set out below. None of these are subject to performance conditions. Additional details regarding these options can be found on page 144.

Current directors	Options	Restricted shares
Bob Dudley	–	–
Iain Conn	3,814	–
Dr Brian Gilvary	504,191	197,881
Dr Byron Grote	–	–

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.

There are no directors or members of senior management who own more than 1% of the ordinary shares in issue. At 25 February 2013, all directors and senior management as a group held interests in 10,878,365 ordinary shares or their calculated equivalent, 12,805,997 performance shares or their calculated equivalent and 6,475,874 options for ordinary shares or their calculated equivalent under the BP group share option schemes.

2013 remuneration policy

Overview

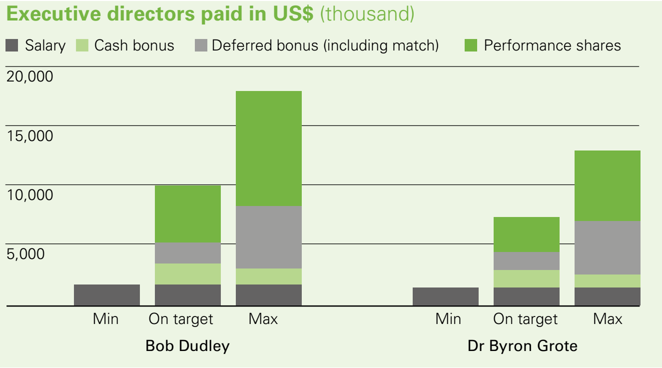
Remuneration policy summary

Component	Policy and opportunity	2013 operation and performance metrics
Salary	Base salaries should be competitive relative to relevant market peer groups and are normally reviewed annually.	Salaries as at 1 January 2013 are: Bob Dudley $1,751,000, Iain Conn £752,000, Dr Brian Gilvary £690,000 and Dr Byron Grote $1,485,000.
Annual bonus	Annual bonus should be based on performance relative to measures and targets reflecting the annual plan, which in turn reflects the strategic priorities of the company. Achieving plan results should equate to on-target bonus. On-target bonus is set at 150% of salary for executive directors with a maximum of 225% of salary.	Bonus measures for 2013 are: • **Safety and operational risk management (30%).** – Loss of primary containment. Ⓡ – Process safety tier 1 events. – Recordable injury frequency. Ⓡ • **Value creation (70%).** – Operating cash flow. Ⓡ – Underlying replacement cost profit. Ⓡ – Total cash costs. – Upstream unplanned deferrals. – Upstream major project delivery. – Downstream net income per barrel. No change from last year on safety and operational risk management. Weight on value creation increased from 50% last year by eliminating rebuilding trust as a measure.
Deferred bonus	A portion of annual bonus should be paid in shares and deferred to add long-term sustainability and shareholder alignment to short-term performance achievement.	One-third of annual bonus is deferred on a mandatory basis and a further one-third can be deferred on a voluntary basis. All deferred shares are matched on a one-for-one basis. All deferred and matched shares vest after three years contingent on an assessment of safety and environmental sustainability over the three-year deferral period. No change from last year.
Performance shares	A large portion of total remuneration for executive directors should be tied to the long-term performance of the company. Shares to a value of 5.5 times salary for the group chief executive and 4 times salary for the other executive directors are normally awarded annually. Vesting of the shares after three years is dependent on performance relative to measures reflecting the strategic priorities of the company. Those shares that vest are held for an additional three-year retention period, after payment of tax on vesting.	The 2013-2015 share element will vest based equally on the following three performance metrics: • **Total shareholder return versus oil majors.** Ⓡ • **Operating cash flow.** Ⓡ • **Strategic imperatives.** – Reserves replacement versus oil majors. Ⓡ – Process safety. Ⓡ – Major project delivery. Executive directors are expected to develop a personal shareholding of five times salary before shares are released. No change from last year with the exception of major project delivery replacing rebuilding trust as one of the strategic imperatives, to align with strategy.
Pension and other benefits	Executive directors should participate in the normal company pension and benefit schemes applying in their home countries.	Both UK and US executive directors remain on defined benefit pension plans. UK directors, as for all UK employees who exceed the annual allowance set by legislation, may receive a cash supplement in lieu of future service pension accrual.

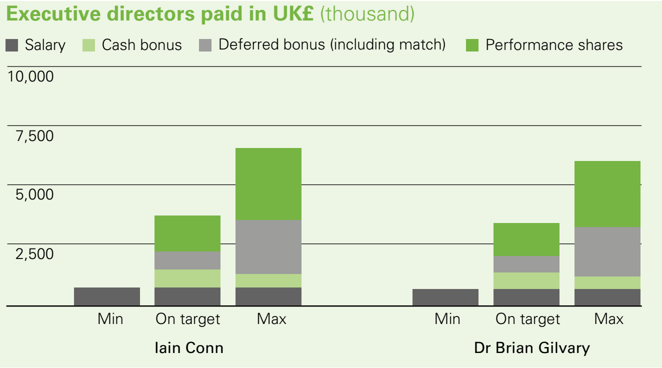
Ⓡ See pages 28-29 for how our bonus measures for 2012 and 2013 are directly linked to business KPIs.

2013 remuneration policy in more depth

Total remuneration is made up of the five components summarized in the table opposite. Each of these is explained in more detail in this section of the report. The total remuneration opportunity for executive directors is strongly performance based and weighted to the long term. As shown below over 90% of the group chief executive's total direct remuneration opportunity (that is at maximum) requires the achievement of demanding performance requirements, and over 80% is long term – three years in the case of deferred bonus and six years for the performance shares.



Executive directors paid in US$ (thousand)



Executive directors paid in UK£ (thousand)

The two charts above provide scenarios for what executive directors may get paid for different levels of performance, consistent with the draft UK regulations on remuneration reporting. Dr Byron Grote's chart shows full-year values for illustration and does not reflect the impact of his announced retirement from the board.

The minimum amount reflects current base salary which is the only part of total direct remuneration that is not performance related.

On-target amounts are based on the following assumptions:

- Current salary.
- Cash bonus reflecting 'on-target' level of 150% of salary of which two-thirds is paid in cash.
- Deferred bonus reflecting one-third of 'on-target' bonus of 150% which is deferred on a mandatory basis and matched on a one-for-one basis.
- Performance shares that vest to a value of one half of the maximum.
- Share prices are assumed to remain constant for calculation purposes.

Maximum amounts are based on the following assumptions:

- Current salary.
- Cash bonus reflecting maximum level of 225% of salary of which one-third is paid in cash.
- Deferred bonus reflecting two-thirds of maximum bonus of 225% which is deferred on a mandatory and voluntary basis, and matched one-for-one.
- Performance shares that fully vest amounting to 5.5 times salary for the group chief executive and 4 times salary for other executive directors.
- Share prices are assumed to remain constant for calculation purposes.

Salary – 2013 policy

As most components of total remuneration are determined as multiples of salary, the remuneration committee makes careful reviews of salaries, normally annually. These reviews include thorough consideration of other large UK and Europe-based global companies, other oil majors, and relevant US companies. They also include similar consideration of the salary treatment throughout the company, as well as company performance and investor perspectives. It is expected that salaries for executive directors will be reviewed mid-year in this context.

Annual bonus – 2013 policy

Operation

For 2013, all executive directors will again be eligible for a total bonus (including deferral) of 150% of salary at target and 225% at maximum. Bob Dudley's bonus will be based entirely on group measures as will Dr Brian Gilvary's and Dr Byron Grote's. Iain Conn will have 70% of his bonus based on group results and 30% on his business segment.

The group strategy provides the overall context for the company's key performance indicators and the focus for the annual plan. From this, measures and targets are selected at the start of the year for senior managers, including executive directors, to reflect the key priorities of the business. Measures typically include a range of financial and operating metrics as well as those relating to safety and environment.

The committee has a preference for quantifiable, hard targets that can be factually measured and objectively assessed according to well understood principles and definitions. Where it is more appropriate to have more qualitative measures, the information that will be reviewed to arrive at conclusions is established at the start of the year. Targets are set so that achieving plan levels of performance results in on-target bonus.

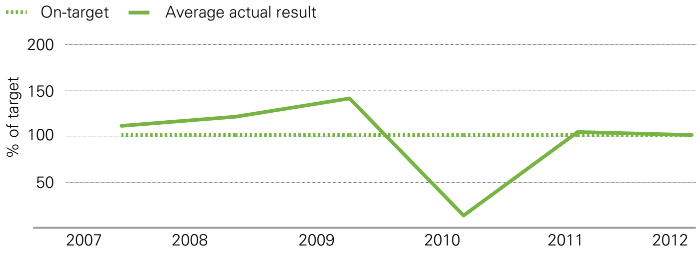
At the end of each year, performance is assessed relative to the measures and targets established at the start of the year, adjusted for any material changes in the market environment (predominantly oil prices).

As in past years, in addition to the specific bonus metrics, the committee will also review the underlying performance of the group in light of the overall business plan, competitors' results, analysts' reports, and seek input from other committees on relevant aspects. When appropriate, the committee may make adjustments to a straight formulaic result based on this fuller information. The committee considers that this informed judgement is important to establishing a fair overall assessment.

The rigorous process followed by the committee has resulted in bonus levels varying considerably over the past several years, reflecting the changing fortunes of the company during the period.

The chart below shows the average annual bonus result (before any deferral) and relative to an on-target level for executive directors for 2012 as well as the previous five years.

History of annual bonus results



Performance measures

The measures used to determine bonus results flow directly from the group's annual plan which reflects the strategic priorities of safety and operational risk management, and reinforcing value creation.

A central strategic priority continues to be safety and managing risk. As last year, performance in this area will account for 30% of group results for bonus purposes. The primary measures used to assess performance will be loss of primary containment, process safety tier 1 events, and recordable injury frequency. The first two of these track process safety while the third reflects personal safety and this balance gives an overall perspective on performance. The committee will also seek the input of the safety, ethics and environment assurance committee (SEEAC) to determine if there are any other factors or metrics that should be considered in arriving at a final assessment at year end.

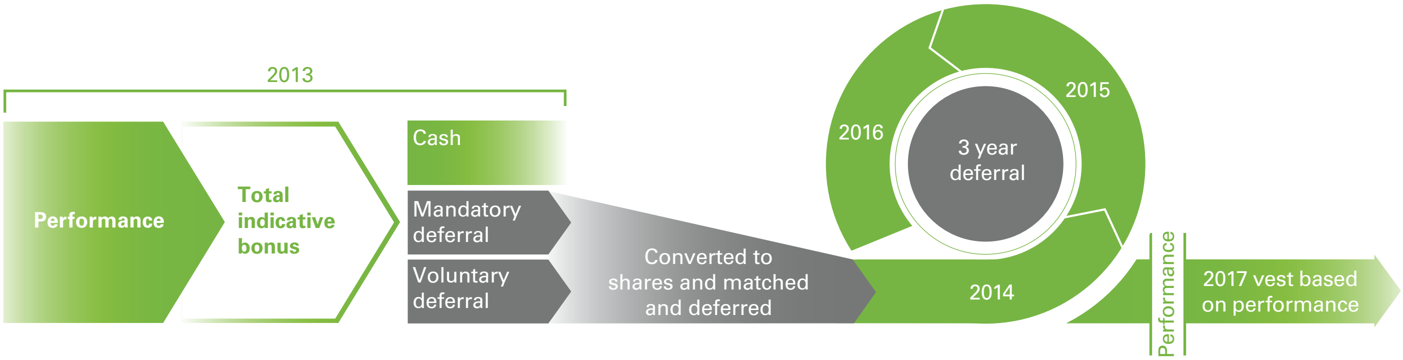
A second set of measures will track performance relative to value creation and account for 70% of group results for bonus purposes. This reflects increased emphasis on restoring value from last year when it accounted for 50%. The 'rebuilding trust' set of measures, accounting for 20% last year, will not feature in 2013. Three financial measures for value creation include operating cash flow, underlying replacement cost profit, and total cash cost. Three additional operating metrics include upstream major project delivery, upstream planned deferrals, and Downstream net income per barrel. This set of metrics provides a balance of financial and operating priorities, as well as significant continuity from last year.

The Downstream segment will include specific safety metrics for the segment. Value metrics will include availability, efficiency, and profitability measures, as well as divestments and major project delivery.

Deferred bonus – 2013 policy

The structure of deferred bonus, paid in shares, places increased focus on long-term alignment with shareholders, and reinforces the critical importance of maintaining high safety and environmental standards. It effectively translates the outcome of a portion of the annual bonus into a long-term plan with additional performance hurdles. As shown below, the performance results of 2013 will form the basis for determining the deferred bonus in 2014.

Timeline for 2013 deferred bonus



Operation

For 2013, as last year, one-third of the annual bonus will be deferred on a mandatory basis into shares for three years. Under the rules of the plan, the average share price over the three days following announcement of full-year results is used to determine the number of shares. Deferred shares are matched by the company on a one-for-one basis.

Executive directors may defer a further one-third of their annual bonus into shares on a voluntary basis, which will be capable of vesting, and will qualify for matching, on the same basis as set out above.

Both deferred and matched shares will vest in early 2017 contingent on an assessment of safety and environmental sustainability over the three-year deferral period. Where shares vest, the executive director will also receive additional shares representing the value of the re-invested dividends.

Performance measures

Since 2010, the deferred bonus has been subject to a safety and environmental sustainability hurdle, and this will again be applied this coming year.

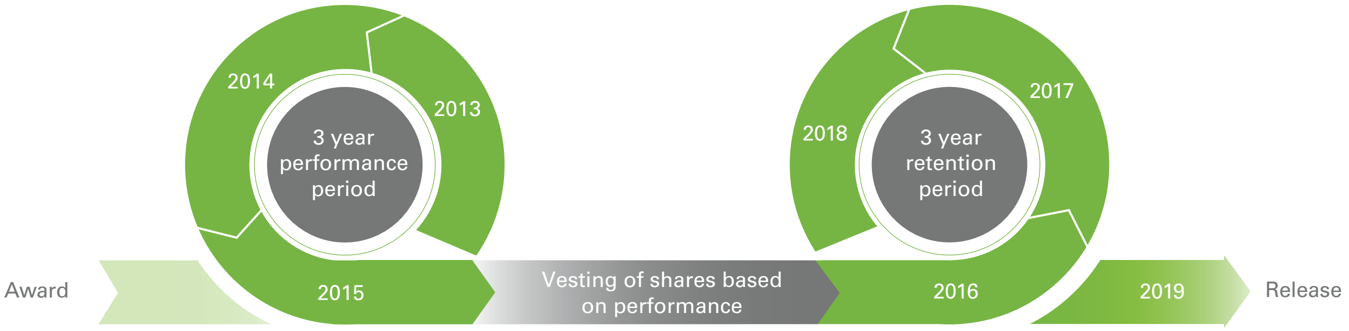
If the committee assesses that there has been a material deterioration in safety and environmental metrics, or there have been major incidents revealing underlying weaknesses in safety and environmental management, then it may conclude that shares should vest in part, or not at all. In reaching its conclusion, the committee will obtain advice from the SEEAC.

The committee believes that this safety and environmental hurdle is appropriate for several reasons. First, high standards in this area are an important priority of BP's strategy. Second, maintaining safety and environmental standards over the long-term is a good qualitative determinant of the sustainability of the business. Third, this non-financial hurdle will complement the financial and operational performance conditions applicable to performance share awards.

Performance shares – 2013 policy

The performance share element reflects the committee's policy that a large proportion of total remuneration is tied to long-term performance. A three-year performance period, combined with a further three-year retention period for those shares that vest, creates a six-year incentive structure which is designed to ensure executive interests are aligned with those of shareholders.

Timeline for 2013-2015 share element



Operation

Performance shares are awarded conditionally at the start of each year. For 2013, as last year, shares have been awarded to a value of 5.5 times salary for the group chief executive and 4 times salary for the other executive directors (the maximum allowed under the plan).

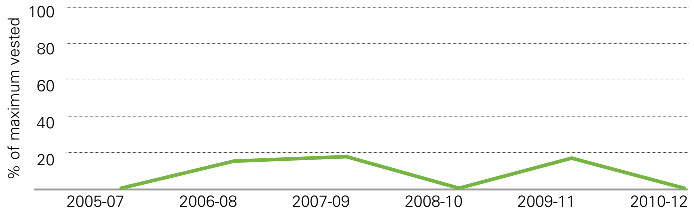
Performance shares will only vest to the extent that performance conditions, as described below, are met. The committee also has an overriding discretion, in exceptional circumstances, to reduce the number of shares that vest.

Where shares vest, the executive director will receive additional shares representing the value of the re-invested dividends on those shares. Sufficient shares may be sold at vesting to discharge tax liabilities.

The remaining vested shares will normally be subject to a compulsory retention period of a further three years. Furthermore, these shares will only be released once the company's minimum shareholding target of five times salary has been met.

The history of vesting of the share element for the past plan and the five previous ones is shown below, reflecting both demanding performance conditions and poor company performance during this period.

History of share element vesting



2013 performance measures

Performance conditions for the 2013-2015 share element will be aligned with the company's strategic agenda which continues to focus on value creation and reinforcing safety and operational risk management. Vesting of shares will be based one-third on BP's total shareholder return (TSR) compared to other oil majors, reflecting the central importance of restoring the value of the company. A further third will be based on the operating cash flow of the company, reflecting a central element of value creation. The final third will be based on a set of strategic imperatives; in particular, reserves replacement, safety and operational risk, and major project delivery.

For the relative measures, TSR and the reserves replacement ratio, the comparator group will consist of ExxonMobil, Shell, Total and Chevron. This group can be altered if circumstances change, for example, if there is significant consolidation in the industry. While a narrow group, it continues to represent the comparators that both shareholders and management use in assessing relative performance.

The TSR will be calculated as the share price performance over the three-year period, assuming dividends are reinvested. All share prices will be averaged over the three-month period before the beginning and end of the performance period. They will be measured in US dollars.

The reserves replacement ratio is defined according to industry standard specifications and its calculation is audited. As in previous years, the methodology used for the relative measures will rank each of the five oil majors on each measure. Performance shares for each component will vest at levels of 100%, 70% and 35% respectively, for performance equivalent to first, second and third rank. No shares will vest for fourth or fifth place.

Operating cash flow has been identified as a core strategic priority of the company. Targets have been established reflecting agreed plans, $100/bbl oil price and other normal operating assumptions.

Finally the remaining strategic imperatives relating to process safety and major project delivery will be determined by a mixture of internal targets and external assessment. In the case of safety, loss of primary containments, process safety tier 1 incidents and recordable injury frequency will provide the key factual data as well as the input of the SEEAC. Major project delivery component will be based on the commissioning success of major projects.

The committee considers that this combination of quantitative and qualitative measures reflects the long-term value creation priorities of the company as well as the key underpinnings for business sustainability. 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 that the formulaic 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 directors' remuneration report following vesting, in line with its commitment to transparency.

Pensions – 2013 policy

Executive directors are eligible to participate in the appropriate pension schemes that apply in their home country and that follow national norms in terms of structure and levels. Details of pension accrual are set out in the table on page 133 and take into account the total amount that could be payable under relevant plans as described further below.

US executive directors

Pension benefits are provided to Bob Dudley and Dr Byron Grote through a combination of tax-qualified and non-qualified benefit plans, consistent with US tax regulations, as applicable.

The BP Retirement Accumulation Plan (US pension plan) is a US tax-qualified plan that features a cash balance formula and includes grandfathering provisions under final average pay formulas for certain members of acquired companies, including Bob Dudley, who participated in the predecessor Amoco pension plan, which was merged into the BP US pension plan effective 1 July 2000.

Bob Dudley was an active member of the Employee Retirement Plan of Amoco Corporation on 30 June 2000 and is classified as an Amoco heritage participant under the US pension plan. As with all Amoco heritage participants, he is entitled to receive the greater of (a) the cash balance benefit under the US pension plan; and (b) the sum of (i) his accrued benefit as of 31 December 2012 under the Amoco heritage plan formula (described below) and (ii) a new cash balance account (established 1 January 2013 with a zero balance). Bob Dudley's benefit under the Amoco heritage plan is based on his average annual eligible earnings (being base salary plus cash bonus, subject to the IRS compensation limit) over the better of (i) the last consecutive 36 months of benefit service preceding his termination date, and (ii) the highest three consecutive calendar years out of his last 10 years of benefit service. Bob Dudley's retirement benefit under the US pension plan is unreduced at age 60 but reduced by 5% per year if taken before age 60.

Dr Byron Grote was an active member of the BP America Retirement Accumulation Plan on 30 June 2000 and is classified as a BP heritage participant. As a BP heritage participant, he is entitled to receive the cash balance benefit under the US pension plan with additional payment options.

BP also provides a number of non-qualified pension plans in which Bob Dudley and Dr Byron Grote participate.

Bob Dudley will receive a benefit under the TNK-BP Supplemental Retirement Plan which is a lump sum benefit based on the same calculation as his benefit under the US pension plan but reflecting his service and earnings at TNK-BP.

The BP Excess Compensation (Retirement) Plan (excess compensation plan) provides a supplemental benefit which is the difference between (a) the benefit accrual under the US pension plan and the TNK-BP Supplement Retirement Plan without regard to the IRS compensation limit (including for this purpose base salary, cash bonus and bonus deferred into a compulsory or voluntary award under the deferred matching element of the EDIP), and (b) the actual benefit payable under the US pension plan and the TNK-BP Supplemental Retirement Plan, applying the IRS compensation limit. The benefit calculation under the heritage Amoco formula includes a reduction of 5% per year if taken before age 60.

Dr Byron Grote will receive a benefit under the BP America Inc. Supplemental Retirement Accumulation Plan (SRAP), which is a lump sum cash balance that only grows with interest based on the greater of the 30-year US Treasury bond interest rate or 5%.

As of 31 December 2012, Dr Byron Grote will also receive a benefit from the BP Supplemental Executive Retirement Benefit Plan (SERB). The benefit payable under this supplemental plan is based on a target of 1.3% of final average earnings (including for this purpose base salary plus cash bonus and bonus deferred into a compulsory or voluntary award under the deferred matching element of the EDIP) for each year of service (without regard for tax limits) less benefits paid under all other BP (US) qualified and non-qualified pension arrangements. The benefit payable under SERB is unreduced at age 60 but reduced by 5% per year if separation occurs before age 60. Benefits payable under this plan are unfunded and therefore paid from corporate assets. As of 31 December 2012, Bob Dudley will not receive a benefit from this plan due to the value of his benefits under the other plans.

UK executive directors

Iain Conn and Dr Brian Gilvary are members of the regular BP pension scheme in respect of service prior to 1 April 2011. 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. Higher accrual rules are offered to employees on the payment of personal contributions.

Since 1 April 2011 the UK directors, Iain Conn and Dr Brian Gilvary, have received a cash supplement in lieu of future service pension accrual in the BP pension scheme. This follows the reduction in the annual allowance applicable to plans such as the BP pension scheme in 2011. Some employees, including the UK directors, have had to cease pension accrual for future service to remain within the new annual allowance. For all these employees the cash supplement is equal to 35% of basic salary.

Until the end of March 2011, pension benefits in excess of the individual lifetime allowance set by legislation were paid via an unapproved, unfunded pension arrangement provided directly by the company. From April 2011 only increases in accrued benefits due to increases in salary in excess of the individual lifetime allowance are covered by their arrangements. Both Iain Conn and Dr Brian Gilvary are covered under this arrangement.

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.

Both Iain Conn and Dr Brian Gilvary were in service at 1 December 2006, and therefore special early retirement terms apply to them. In the event of retirement between 60 and 65, they are entitled to an immediate unreduced pension. In the event of retirement between 55 and 60, they are entitled to an immediate unreduced pension in respect of the proportion of their benefit for service up to 30 November 2006, and are subject to such reduction as the scheme actuary certifies in respect of the period of service after 1 December 2006. For retirees leaving in circumstances approved by the committee the scheme actuary has to date applied a reduction of 3% per annum in respect of the period of service from 1 December 2006 up to the leaving date; a greater reduction can be applied in other circumstances. Those leaving before 55 are entitled to a deferred pension that becomes payable from 55 or later, on the basis set out above. Irrespective of the above, an individual leaving in circumstances of total incapacity is entitled to an immediate unreduced pension as from the leaving date.

Other benefits – 2013 policy

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.

Service contracts

Summary details of each executive director's service agreement are as follows:

Table of contracts

	Service agreement date	Salary as at 1 Jan 2013
Bob Dudley	6 Apr 2009	$1,751,000
Iain Conn	22 Jul 2004	£752,000
Dr Brian Gilvary	22 Feb 2012	£690,000
Dr Byron Grote	7 Aug 2000	$1,485,000

Bob Dudley's contract is with BP Corporation North America Inc. He is seconded to BP p.l.c. under a secondment agreement dated 15 April 2012, which expires on 15 April 2014. Dr Byron Grote's agreement 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 2013 AGM. Both secondments can be terminated by one month's notice by either party and terminate automatically on the termination of their service agreements. Iain Conn's and Dr Brian Gilvary's service agreements are with BP p.l.c.

Each executive director is entitled to pension provision, details of which are summarized on page 133 of this report.

Each executive director is entitled to the following contractual benefits:

- A company car for business and private use, on terms that the company bear all normal servicing, insurance and running costs. Alternatively, the executive director is entitled to a car allowance in lieu.
- Medical and dental benefits; sick pay during periods of absence; tax preparation assistance.
- Indemnification in accordance with applicable law.

Each executive director participates in bonus or incentive arrangements at the committee's sole discretion. Currently, each participates in the discretionary bonus scheme and the EDIP, described on pages 138 and 139 and 140 of this report respectively.

Each executive director may terminate his employment by giving his employer 12 months' written notice. In this event, for business reasons, the employer would not necessarily hold the executive director to his full notice period.

Other than in the case of Dr Brian Gilvary (who became a director on 1 January 2012), the service agreements are expressed to expire at a normal retirement age of 60; however, such executive directors could not, under UK law, be required to retire at this (or any other) age following abolition of the default retirement age.

The employer may lawfully terminate the executive director's employment in the following ways:

- By giving the director 12 months' written notice.
- Without compensation, in circumstances where the employer is entitled to terminate for cause, as defined for the purposes of his service agreement.

Additionally, in the case of Iain Conn and Dr Brian Gilvary, the company may lawfully terminate employment by making a lump sum payment in lieu of notice equal to 12 months' base salary. The company may elect to pay this sum in monthly instalments rather than as a lump sum.

The lawful termination mechanisms described above are without prejudice to the employer's ability in appropriate circumstances to terminate in breach of the notice period referred to above, and thereby to be liable for damages to the executive director.

In the event of termination by the company, each executive director may have an entitlement to compensation in respect of his statutory rights under employment protection legislation in the UK and potentially elsewhere.

The committee considers that its policy on termination payments arising from the contractual provisions summarised above provides an appropriate degree of protection to the director in the event of termination, and is consistent with UK market practice.

Exit payment policy

If it became necessary for the company to terminate an executive director's employment, and therefore to determine a termination payment, the committee's policy would be as follows in relation to the matters described below:

- The director's primary entitlement would be to a termination payment in respect of his service agreement, as set out above. The committee will consider mitigation to reduce the termination payment to a leaving director when appropriate to do so, having regard to the circumstances and the law governing the agreement. Mitigation would not be applicable where a contractual payment in lieu of notice is made. In addition, the director may be entitled to a payment in respect of his statutory rights. Other potential elements are as follows. First, the committee would consider whether the director should be entitled to an annual bonus in respect of the financial year in which the termination occurs; normally, any such bonus would be restricted to the director's actual period of service in that financial year. Second, the committee would consider whether conditional share awards held by the director under the EDIP should lapse on leaving or should, at the committee's discretion, be preserved (in which event the award would normally continue until the normal vesting date and be treated in the manner described on pages 139 and 140 of this report). Any such determination will be made in accordance with the rules of the EDIP, as approved by shareholders. Third, if the departing director is eligible for an early retirement pension, the committee would consider, if relevant under the terms of the plan in which the director participates, the extent of any actuarial reduction that should be applied.
- In determining the overall termination arrangements, the committee would have regard to all relevant circumstances, and would therefore distinguish between types of leaver and the circumstances under which the director left the company. This is primarily relevant to consideration of how discretion would be exercised in relation to conditional share awards under the EDIP. It is also relevant where a departing director has a right to an early retirement pension. UK directors who leave in circumstances approved by the committee may have a favourable actuarial reduction applied to their pensions (which has to date been 3%). Departing directors who leave in other circumstances are subject to a greater reduction.
- The performance of the leaving director would be taken into account in various respects. In particular, in deciding whether to exercise discretion to preserve EDIP awards, the committee would have regard to the director's performance during the performance cycle of the relevant awards, as well as a range of other relevant factors, including the proximity of the award to its maturity date.
- The committee would also have regard to all other relevant factors, including consideration of whether a contractual provision in the director's arrangements complied with best practice at the time the director's employment was terminated as well as at the time the provision was agreed to.

Director leaving the board

Dr Byron Grote will be retiring from the board at the 2013 AGM, and ceasing employment with the company soon after. Under the rules of the EDIP, his outstanding performance share awards pertaining to the 2011-2013, 2012-2014 and 2013-2015 performance periods, as well as the matching share awards in respect of 2010, 2011 and 2012 deferred bonus will all be prorated to reflect actual service during the applicable three-year performance periods. These share awards will vest at the normal time to the extent the performance targets or hurdles are met. His 2013 bonus eligibility will likewise be prorated to reflect his service and based on group results for the year. He will not receive any termination payments on leaving service.

Further details

Executive directors – external appointments

The board supports executive directors taking up appointments outside the company to broaden their knowledge and experience. 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:

Director	Appointee company	Additional position held at appointee company	Total fees
Iain Conn	Rolls-Royce	Senior independent director	£72,000
Dr Byron Grote	Unilever	Audit committee member	Unilever PLC £47,500 Unilever NV €54,935

Performance shares (audited)

			Share element interests				Interests vested in 2012 and 2013		
			Potential maximum performance shares[a]						
	Performance period	Date of award of performance shares	At 1 Jan 2012	Awarded 2012	At 31 Dec 2012	Awarded 2013	Number of ordinary shares vested[b]	Vesting date	Market price of each share at vesting £
Bob Dudley[c]	2009-2011	06 May 2009	539,634	–	–	–	101,735	15 Feb 2012	4.98
	2010-2012	09 Feb 2010	581,082	–	581,082	–	0	–	–
	2011-2013	09 Mar 2011	1,330,332	–	1,330,332	–	–	–	–
	2012-2014	08 Mar 2012[d]	–	1,343,712	1,343,712	–	–	–	–
	2013-2015	11 Feb 2013	–	–	–	1,393,032	–	–	–
Iain Conn	2008-2013[e]	13 Feb 2008	133,452	–	133,452	–	145,489	7 Feb 2013	4.58
	2009-2011	11 Feb 2009	780,816	–	–	–	149,259	15 Feb 2012	4.98
	2010-2012	09 Feb 2010	656,813	–	656,813	–	0	–	–
	2011-2013	09 Mar 2011	623,025	–	623,025	–	–	–	–
	2012-2014	08 Mar 2012[d]	–	660,663	660,663	–	–	–	–
	2013-2015	11 Feb 2013	–	–	–	699,535	–	–	–
Dr Brian Gilvary	2010-2012[f]	15 Mar 2010	60,000	–	60,000	–	65,414	15 Jan 2013	4.58
	2011-2013[f]	14 Mar 2011	67,500	–	67,500	–	–	–	–
	2010-2012[g]	15 Mar 2010	22,500	–	22,500	–	–	–	–
	2011-2013[g]	14 Mar 2011	22,500	–	22,500	–	–	–	–
	2012-2014	08 Mar 2012[d]	–	624,434	624,434	–	–	–	–
	2013-2015	11 Feb 2013	–	–	–	641,860	–	–	–
Dr Byron Grote[c]	2009-2011	11 Feb 2009	992,928	–	–	–	187,193	15 Feb 2012	4.98
	2010-2012	09 Feb 2010	801,894	–	801,894	–	0	–	–
	2011-2013	09 Mar 2011	785,394	–	785,394	–	–	–	–
	2012-2014	08 Mar 2012[d]	–	828,936	828,936	–	–	–	–
	2013-2015	11 Feb 2013	–	–	–	859,212	–	–	–
Former directors									
Dr Anthony Hayward	2009-2011	11 Feb 2009	755,512[h]	–	–	–	144,422	15 Feb 2012	4.98
	2010-2012	09 Feb 2010	303,948[h]	–	303,948	–	0	–	–
Andrew Inglis	2009-2011	11 Feb 2009	520,544[h]	–	–	–	99,506	15 Feb 2012	4.98
	2010-2012	09 Feb 2010	218,938[h]	–	218,938	–	0	–	–

[a] BP's performance is measured against the oil sector. For awards under the 2010-2012 plan, performance conditions were measured one-third on TSR against ExxonMobil, Shell, Total, ConocoPhillips and Chevron and two-thirds on a balanced scorecard of underlying performance. For awards under the 2011-2013 plan, performance conditions are measured 50% on TSR against ExxonMobil, Shell, Total, ConocoPhillips and Chevron; 20% on reserves replacement against the same peer group; and 30% against a balanced scorecard of strategic imperatives. For awards under the 2012-2014 plan, performance conditions are measured one-third on TSR against ExxonMobil, Shell, Total and Chevron; one-third on safety and operational risk management; and one-third on a balanced scorecard of strategic imperatives. Each performance period ends on 31 December of the third year.

[b] Represents vestings 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 vested.

[c] Dr Byron Grote and Bob Dudley receive awards in the form of ADSs. The above numbers reflect calculated equivalents in ordinary shares. One ADS is equivalent to six ordinary shares.

[d] The market price of ordinary shares on 8 March 2012 was £4.94 and for ADSs was $47.11.

[e] Restricted award under share element of EDIP. As reported in the 2007 directors' remuneration report in February 2008, the committee awarded Iain Conn restricted shares, in two tranches of 133,452 shares each and on vesting include re-invested dividends on the shares vested. The total vesting of the first tranche was 155,695 shares at £4.91 on 22 February 2011. The remaining award, noted above, vested on 7 February 2013, the fifth anniversary of the award at £4.58.

[f] Dr Brian Gilvary was conditionally awarded shares under the Executive Performance Plan prior to his appointment as a director. The vesting of these shares is not subject to further performance conditions.

[g] Dr Brian Gilvary was conditionally awarded shares under the Competitive Performance Plan prior to his appointment as a director. The vesting of these shares is subject to performance conditions.

[h] Potential maximum of performance shares reflect actual service during performance period on a pro-rated basis.

Erratum: Please note that in footnote 'a' above, the reference to awards under the 2012-2014 plan, **'one-third on safety and operational risk management'** should instead read **'one-third on operating cash flow'**. Full details of the performance conditions are spelt out correctly in the 2011 directors' remuneration report on page 147.

Deferred shares (audited)

					Deferred share element interests				Interests vested in 2012 and 2013		
					Potential maximum performance shares						
	Bonus year	Type	Performance period	Date of award of deferred shares	At 1 Jan 2012	Awarded 2012[a]	At 31 Dec 2012	Awarded 2013	Number of ordinary shares vested	Vesting date	Market price of each share at vesting £
Bob Dudley[b]	2011	Comp	2012-2014	08 Mar 2012	–	109,206	109,206	–	–	–	–
		Vol	2012-2014	08 Mar 2012	–	109,206	109,206	–	–	–	–
		Mat	2012-2014	08 Mar 2012	–	218,412	218,412	–	–	–	–
	2012	Comp	2013-2015	11 Feb 2013	–	–	–	114,690	–	–	–
		Vol	2013-2015	11 Feb 2013	–	–	–	114,690	–	–	–
		Mat	2013-2015	11 Feb 2013	–	–	–	229,380	–	–	–
Iain Conn	2010	Comp	2011-2013	09 Mar 2011	21,384	–	21,384	–	–	–	–
		Mat	2011-2013	09 Mar 2011	21,384	–	21,384	–	–	–	–
	2011	Comp	2012-2014	08 Mar 2012	–	80,652	80,652	–	–	–	–
		Vol	2012-2014	08 Mar 2012	–	80,652	80,652	–	–	–	–
		Mat	2012-2014	08 Mar 2012	–	161,304	161,304	–	–	–	–
	2012	Comp	2013-2015	11 Feb 2013	–	–	–	80,648	–	–	–
		Vol	2013-2015	11 Feb 2013	–	–	–	80,648	–	–	–
		Mat	2013-2015	11 Feb 2013	–	–	–	161,296	–	–	–
Dr Brian Gilvary[c]	2009	DAB	2010-2012	15 Mar 2010	87,394	–	87,394	–	95,279	15 Jan 2013	4.58
	2010	DAB	2011-2013	14 Mar 2011	44,971	–	44,971	–	–	–	–
	2011	DAB	2012-2014	15 Mar 2012	–	73,624	73,624	–	–	–	–
	2012	Comp	2013-2015	11 Feb 2013	–	–	–	78,815	–	–	–
		Vol	2013-2015	11 Feb 2013	–	–	–	78,815	–	–	–
		Mat	2013-2015	11 Feb 2013	–	–	–	157,630	–	–	–
Dr Byron Grote[b]	2010	Comp	2011-2013	09 Mar 2011	26,604	–	26,604	–	–	–	–
		Vol	2011-2013	09 Mar 2011	26,604	–	26,604	–	–	–	–
		Mat	2011-2013	09 Mar 2011	53,208	–	53,208	–	–	–	–
	2011	Comp	2012-2014	08 Mar 2012	–	91,638	91,638	–	–	–	–
		Vol	2012-2014	08 Mar 2012	–	91,638	91,638	–	–	–	–
		Mat	2012-2014	08 Mar 2012	–	183,276	183,276	–	–	–	–
	2012	Comp	2013-2015	11 Feb 2013	–	–	–	97,278	–	–	–
		Vol	2013-2015	11 Feb 2013	–	–	–	97,278	–	–	–
		Mat	2013-2015	11 Feb 2013	–	–	–	194,556	–	–	–

Comp = Compulsory.
Vol = Voluntary.
Mat = Matching.
DAB = Deferred Annual Bonus Plan.

[a] The market price of ordinary shares on 8 March 2012 was £4.94 and for ADSs was $47.11.

[b] Bob Dudley and Dr Byron Grote received awards in the form of ADSs. The above numbers reflect calculated equivalents in ordinary shares. One ADS is equivalent to six ordinary shares.

[c] Dr Brian Gilvary was granted the shares under the DAB prior to his appointment as a director. The vesting of these shares is not subject to further performance conditions and he receives deferred shares at each scrip payment date as part of his election choice.

Share interests in share option plans (audited)

	Option type	At 1 Jan 2012	Granted	Exercised	At 31 Dec 2012	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
Bob Dudley[a]	BP SOP	17,835	–	–	–[b]	$48.99	–	18 Feb 2005	17 Feb 2012
	BP SOP	17,835	–	–	17,835	$38.10	–	17 Feb 2006	16 Feb 2013
Iain Conn	SAYE	617	–	617	–	£4.87	£4.92[c]	01 Sep 2011	29 Feb 2012
	SAYE	605	–	–	605	£4.20	–	01 Sep 2012	28 Feb 2013
	SAYE	3,017	–	–	3,017	£3.68	–	01 Sep 2016	28 Feb 2017
	SAYE	–	797	–	797	£3.16	–	01 Sep 2015	28 Feb 2016
	EXEC	130,000	–	–	–[b]	£5.72	–	18 Feb 2005	18 Feb 2012
Dr Brian Gilvary	BP 2011	500,000	–	–	500,000	£4.44	–	07 Sep 2014	07 Sep 2021
	SAYE	4,191	–	–	4,191	£3.68	–	01 Sep 2016	28 Feb 2017

The closing market prices of an ordinary share and of an ADS on 31 December 2012 were £4.25 and $41.64 respectively.
During 2012 the highest market prices were £5.12 and $48.34 respectively and the lowest market prices were £3.60 and $36.25 respectively.
BP SOP = BP Share Option Plan. These options were granted to Bob Dudley prior to his appointment as a director and are not subject to performance conditions.
EXEC = Executive Share Option Scheme. These options were granted to Iain Conn prior to his appointment as a director and are not subject to performance conditions.
BP 2011 = BP 2011 Plan. These options were granted to Dr Brian Gilvary prior to his appointment as a director and are not subject to performance conditions.
SAYE = Save As You Earn employee share scheme.

[a] Numbers shown are ADSs under option. One ADS is equivalent to six ordinary shares.

[b] Options lapsed.

[c] Options exercised on 29 February 2012. Closing market price for information. Shares were retained after exercise of options.

Non-executive directors' remuneration

Policy

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, motivate and retain world-class non-executive talent.
- Remuneration of non-executive directors should be proportional to their contribution towards the interests of the company.
- Remuneration practice should be consistent with recognized best practice standards for non-executive directors' remuneration.
- As a UK-listed company, the quantum and structure of non-executive director remuneration will primarily be compared against best UK practice.
- 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.
- Remuneration for non-executive directors is reviewed annually.

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.

The review of non-executive remuneration undertaken in 2012 benchmarked the structure and fees of BP non-executive directors against the ten largest companies by market capitalization in the FTSE100. The review concluded that fee levels, which had not been increased since 2007, had fallen below the comparator group and changes were made to the following fee elements:

- Increase in the basic board member fee from £75,000 to £90,000.
- Increase in committee membership fees from £5,000 to £20,000.
- Increase in the remuneration committee chairmanship fee from £20,000 to £30,000.

All other fees remained unchanged.

The review also concluded that the company should be willing to reimburse professional fees up to £5,000 per annum incurred by non-executive directors based outside the UK in connection with advice and assistance on UK tax compliance matters.

Fee structure

The table below shows the fee structure for non-executive directors from 1 October 2012:

	Fee level £ thousand
Chairman[a]	750
Senior independent director[b]	120
Board member	90
Audit, Gulf of Mexico, remuneration and safety, ethics and environment assurance committees chairmanship fees[c]	30
Committee membership fee[d]	20
Intercontinental travel allowance	5

[a] The chairman remains ineligible for committee chairmanship and membership fees or intercontinental travel allowance. He has the use of a fully maintained office for company business, a chauffeured car and security advice in London. He receives secretarial support as appropriate to his needs in Sweden.

[b] The senior independent director is still eligible for committee chairmanship fees and intercontinental travel 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 audit, Gulf of Mexico, SEEA and remuneration committees.

2012 remuneration (audited)

All fees in £ thousand	Total fees	
	2012	2011
Carl-Henric Svanberg	750	750
Paul Anderson	149	128
Admiral Frank Bowman	126	120
Antony Burgmans	120	100
Cynthia Carroll	98	85
George David[a]	135	128
Ian Davis	128	160
Professor Dame Ann Dowling[b c]	97	–
Brendan Nelson	119	103
Phuthuma Nhleko	123	113
Andrew Shilston[d]	125	–
Director leaving the board in 2012		
Sir William Castell[e]	42	168

[a] In addition, George David received £28,000 for chairing the BP technology advisory council.

[b] Appointed 3 February 2012.

[c] In addition, Professor Dowling received £4,166 for her membership of the BP technology advisory council.

[d] Appointed 1 January 2012 and became senior independent director in April 2012.

[e] Retired from the board in April 2012.

No share or share option awards were made to any non-executive director in respect of service on the board during 2012.

Non-executive directors have letters of appointment that 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.

Past directors

Sir Ian Prosser (who retired as a non-executive director of BP in April 2010) was appointed as a director and non-executive chairman of BP Pension Trustees Limited in 1 October 2010. During 2012, he received £100,000 for this role.

Peter Sutherland (who was chairman of BP until 31 December 2009) continued his membership of the BP international advisory board after his retirement from the board of BP p.l.c. During 2012, he received €100,000 for this role.

This directors' remuneration report was approved by the board and signed on its behalf by David J Jackson, company secretary on 6 March 2013.

Regulatory information

Internal Control Revised Guidance for Directors (Turnbull)

In discharging its responsibility for the company's risk management and internal control systems under the UK Corporate Governance Code, 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 UK Corporate Governance Code including principle C.2 (risk management and internal control).

The board has an established process by which the effectiveness of the system of internal control (which includes the risk management system) is reviewed as required by provision C.2.1 of the UK Corporate Governance Code. This process enables the board and its committees to consider the system of internal control being operated for managing significant risks, including strategic, safety and operational and compliance and control risks, throughout the year. Material joint ventures and associates have not been dealt with as part of the group in this process.

As part of this process, the board and the audit, Gulf of Mexico and safety, ethics and environment assurance committees requested, received and reviewed reports from executive management, including management of the business segments, divisions and functions, at their regular meetings.

In considering the systems, the board noted that such systems are 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 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 UK Corporate Governance Code provided by the Financial Reporting Council. In December 2012, 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 2013 reviewed a report from the general auditor as part of the board's annual review of the risk management and internal control systems. The report described the annual summary of internal audit's consideration of elements of BP's system of internal control over significant risks arising in the categories of strategic, safety and operational and compliance and control and considered the control environment for the group. The report 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 ethics and compliance officer, head of safety and operational risk 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 (Turnbull).

Subject to determining any additional appropriate actions arising from items still in process, 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.

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 Corporate Governance 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 that 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 committee reports on pages 120-126). 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 that 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. The BP audit committee does not have direct responsibility for the appointment, reappointment or removal of the independent auditors – instead, it follows the UK Companies Act 2006 by making recommendations to the board on these matters for it to put forward for shareholder approval at the AGM.

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'. The board determined that Brendan Nelson possessed such expertise and also possesses the financial and audit committee experiences set forth in both the UK Corporate Governance Code and SEC rules (see Audit committee report on pages 120-122). Brendan Nelson is the audit committee financial expert as defined in Item 16A of Form 20-F.

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 that 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 that address the conduct of directors. In addition BP has adopted a code of ethics for senior financial officers as required by the SEC. BP considers that these codes and policies address the matters specified in the NYSE rules for US companies.

Code of ethics

The company has adopted a code of ethics for its group chief executive, chief financial officer, group controller, general auditor 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.

BP also has a code of conduct, which is applicable to all employees. This was updated (and published) on 1 January 2012.

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 believes 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.

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 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 2012 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 (Turnbull). Based on this assessment, management has determined that BP's internal control over financial reporting as of 31 December 2012 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. BP's internal control over financial reporting as of 31 December 2012 has been audited by Ernst & Young, an independent registered public accounting firm, as stated in their report appearing on page 181 of *BP Annual Report and Form 20-F 2012*.

Changes in internal control 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.

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 are 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; 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. BP operates a two-tier system for audit and non-audit services. For audit related services, the audit committee has a pre-approved aggregate level, within which specific work may be approved by management. Non-audit services, including tax services, are pre-approved for management to authorize per individual engagement, but above a defined level must be approved by the chairman of the audit committee or the full committee. 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. Any proposed service not included in the approved service list must be approved in advance by the audit committee chairman and reported to the committee, or approved by the full audit committee in advance of commencement of the engagement.

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 16 on page 212 and Audit committee report on pages 120-122 for details of audit fees.)

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 2006 (Act) and the company's Memorandum and Articles of Association. For information on where investors can obtain copies of the Memorandum and Articles of Association see Documents on display on page 159.

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 Act. Further amendments to the Articles of Association were approved by shareholders at the AGM held on 15 April 2010. There have been no further amendments to the Articles of Association.

Objects and purposes

BP is incorporated under the name BP p.l.c. and is registered in England and Wales with the registered number 102498. The provisions regulating the operations of the company, known as its 'objects', were historically stated in a company's memorandum. The Act abolished the need to have object provisions and so at the AGM held on 15 April 2010 shareholders approved the removal of its objects clause together with all other provisions of its Memorandum that, by virtue of the Act, are treated as forming part of the company's Articles of Association.

Directors

The business and affairs of BP shall be managed by the directors. The company's Articles of Association provide that directors may be appointed by the existing directors or by the shareholders in a general meeting. Any person appointed by the directors will hold office only until the next general meeting and will then be eligible for re-election by the shareholders. There is no requirement for a director to retire on reaching any age.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which the director has a material interest other than by virtue of such director's 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 or any of its subsidiaries.
- Any proposal in which the director is interested, concerning the underwriting of company securities or debentures or the giving of any security to a third party for a debt or obligation of the company or any of its subsidiaries.
- Any proposal concerning any other company in which the director is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that the director and persons connected with such director are not the holder or holders of 1% or more of the voting interest in the shares of such company.
- Any proposal concerning the purchase or maintenance of any insurance policy under which the director may benefit.

The 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 the director's interest at a meeting of the directors of the company. The definition of 'interest' includes the interests of spouses, children, companies and trusts. The 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 affected 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 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.

At the company's AGM held on 15 April 2010, shareholders approved the introduction of a Scrip Dividend Programme (Programme) and to include provisions in the Articles of Association to enable the company to operate the Programme. The Programme enables ordinary shareholders and BP ADS holders to elect to receive new fully paid ordinary shares (or BP ADSs in the case of BP ADS holders) instead of cash. The operation of the Programme is always subject to the directors' decision to make the scrip offer available in respect of any particular dividend. Should the directors decide not to offer the scrip in respect of any particular dividend, cash will automatically be paid instead.

Apart from shareholders' rights to share in BP's profits by dividend (if any is declared or announced), 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 N.A., 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 two types: ordinary or special. An annual general meeting must be held once in every year.

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. A special resolution requires 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 a general meeting is 14 days subject to the company obtaining annual shareholder approval, failing which, a 21-day notice period will apply.

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 a special 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 to be entitled to receive notice of shareholders' meetings. 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 are described on page 150 under the heading Voting rights.

Under the Act, the AGM of shareholders must be held within the six-month period once every year. 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 BP ADSs, other than limitations that would generally apply to all of the shareholders and limitations applicable to certain countries and persons subject to EU economic sanctions.

Disclosure of interests in shares

The Act permits a public company to give notice to any person whom the company believes to be or, at any time during the three years prior to the issue of the notice, to have been interested in its voting shares requiring them 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.

Shareholder information

Called-up share capital

Details of the allotted, called-up and fully-paid share capital at 31 December 2012 are set out in Financial statements – Note 38 on page 245.

At the AGM on 12 April 2012, authorization was given to the directors to allot shares up to an aggregate nominal amount equal to $3,163 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 $237 million, without having to offer such shares to existing shareholders. These authorities are given for the period until the next AGM in 2013 or 12 July 2013, whichever is the earlier. These authorities are renewed annually at the AGM.

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 electronically to the exchange 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 on the New York Stock Exchange (NYSE) in the form of ADSs, for which JPMorgan Chase Bank, N.A. is the depositary (the Depositary) and transfer agent. The Depositary's principal office is 1 Chase Manhattan Plaza, N.A., Floor 58, New York, NY 10005-1401, 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 and ADSs for the periods shown. These are derived from the highest and lowest sales prices as reported on the LSE and NYSE, respectively.

		Pence		Dollars
		Ordinary shares		American depositary shares[a]
	High	Low	High	Low
Year ended 31 December				
2008	657.25	370.00	77.69	37.57
2009	613.40	400.00	60.00	33.71
2010	658.20	296.00	62.38	26.75
2011	514.90	361.25	49.50	33.63
2012	**512.00**	**385.09**	**48.33**	**36.25**
Year ended 31 December				
2011: First quarter	514.90	431.00	49.50	42.51
Second quarter	480.23	425.00	47.45	41.26
Third quarter	483.04	361.25	47.09	35.10
Fourth quarter	477.54	363.95	45.83	33.63
2012: First quarter	**512.00**	**455.05**	**48.33**	**42.85**
Second quarter	**475.47**	**385.09**	**45.60**	**36.25**
Third quarter	**456.00**	**417.03**	**44.15**	**39.13**
Fourth quarter	**464.71**	**416.35**	**43.90**	**39.59**
2013: First quarter (to 19 February)	**482.33**	**426.50**	**45.45**	**41.42**
Month of				
September 2012	**454.17**	**417.03**	**44.15**	**40.33**
October 2012	**464.71**	**423.75**	**43.90**	**41.27**
November 2012	**447.99**	**416.35**	**43.24**	**39.59**
December 2012	**435.69**	**420.50**	**42.31**	**40.82**
January 2013	**482.33**	**426.50**	**45.45**	**42.06**
February 2013 (to 19 February)	**474.45**	**443.60**	**44.81**	**41.42**

[a] One 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.

On 19 February 2013, 863,865,919.5 ADSs (equivalent to approximately 5,183,195,517 ordinary shares or some 27.05% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 104,889 ADS holders. Of these, about 103,656 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 789,140,307 underlying holders.

On 19 February 2013, there were approximately 295,062 holders of record of ordinary shares. Of these holders, around 1,604 had registered addresses in the US and held a total of some 4,424,855 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.

Dividends

When dividends are paid on its ordinary shares, BP's policy is to pay interim dividends on a quarterly basis.

BP's policy is also to announce dividends for ordinary shares in US dollars and state an equivalent sterling dividend. Dividends on BP ordinary shares will be paid in sterling and on BP ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the market exchange rates in London over the four business days prior to the sterling equivalent 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.

Information regarding dividends announced and paid by the company on ordinary shares and preference shares is provided in Financial statements – Note 19 on page 214.

A Scrip Dividend Programme (Scrip) was approved by shareholders in 2010 which enables BP ordinary shareholders and ADS holders to elect to receive new fully paid BP ordinary shares (or ADSs in the case of ADS holders) instead of cash. The operation of the Scrip is always subject to the directors' decision to make the Scrip offer available in respect of any particular dividend. Should the directors decide not to offer the Scrip in respect of any particular dividend, cash will automatically be paid instead.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on pages 38-44 and other matters that may affect the business of the group set out in Our strategy on pages 20-21 and in Liquidity and capital resources on pages 90-93.

The following table shows dividends announced and paid by the company per ADS for each of the past five years.

Dividends per ADS[a]		March	June	September	December	Total
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[b]	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
2010	UK pence	52.07	–	–	–	52.07
	US cents	84	–	–	–	84
2011	UK pence	26.02	25.68	25.90	26.82	104.42
	US cents	42	42	42	42	168
2012	**UK pence**	**30.57**	**30.90**	**30.10**	**33.53**	**125.10**
	US cents	**48**	**48**	**48**	**54**	**198**

[a] Dividends announced and paid by the company on ordinary and preference shares is provided in Financial statements Note 19 on page 214.

[b] 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.

UK foreign exchange controls on dividends

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, other than restrictions applicable to certain countries and persons subject to EU economic sanctions.

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 other than limitations that would generally apply to all of the shareholders and limitations applicable to certain countries and persons subject to EU economic sanctions.

Shareholder taxation information

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 US 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, 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.

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 after 2012 that constitute qualified dividend income will be taxable to the holder at a preferential rate, 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. In the case of a non-corporate US holder whose taxable income does not exceed $400,000 ($450,000 in the case of a joint filer), such dividends will be taxed at a maximum rate of 15%. Such dividends paid to a non-corporate US holder whose income is above these dollar thresholds will be subject to tax at a rate of 20%. These dollar thresholds will be adjusted for inflation for tax years after 2013. 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 preferential 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 section below.

In addition, the taxation of dividends may be subject to the rules for passive foreign investment companies (PFIC), described below under 'Taxation of capital gains – US federal income taxation'. Distributions made by a PFIC do not constitute qualified dividend income and are not eligible for the preferential tax rate applicable to such income.

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 who 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. Any capital gain of a non-corporate US holder is taxed at a preferential rate if the holder's holding period for such ordinary shares or ADSs exceeds one year. In the case of a non-corporate US holder whose taxable income does not exceed $400,000 ($450,000 in the case of a joint filer), such gain will be taxed at a maximum rate of 15%. Such gain recognized by a non-corporate US holder whose income is above these dollar thresholds will be subject to tax at a rate of 20%. These dollar thresholds will be adjusted for inflation for tax years after 2013.

Gain or loss from the sale or other disposition of ordinary shares or ADSs 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, any 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

Scrip Dividend Programme

The company has an optional Scrip Dividend Programme, wherein holders of BP ordinary shares or ADSs may elect to receive any 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 to both inheritance tax and 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.

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. For ADR holders electing to receive ADSs instead of cash, after the 2012 first quarter dividend payment

HM Revenue & Customs no longer seeks to impose 1.5% stamp duty reserve tax on issues of UK shares and securities to non-EU clearance services and depositary receipt systems.

Major shareholders

The disclosure of certain major and significant shareholdings in the share capital of the company is governed by the Companies Act 2006, the UK Financial Services Authority's Disclosure and Transparency Rules (DTR) and the US Securities Exchange Act of 1934.

Register of members holding BP ordinary shares as at 31 December 2012

Range of holdings	Number of ordinary shareholders	Percentage of total ordinary shareholders	Percentage of total ordinary share capital excluding shares held in treasury
1-200	59,427	20.03	0.02
201-1,000	107,447	36.23	0.30
1,001-10,000	117,024	39.46	1.83
10,001-100,000	11,072	3.73	1.16
100,001-1,000,000	882	0.30	1.74
Over 1,000,000[a]	728	0.25	94.95
Totals	296,580	100.00	100.00

[a] Includes JPMorgan Chase Bank, N.A. holding 26.91% 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 2012[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	60,231	56.96	0.40
201-1,000	28,844	27.28	1.60
1,001-10,000	15,759	14.90	4.85
10,001-100,000	899	0.85	1.79
100,001-1,000,000	9	0.01	0.15
Over 1,000,000[b]	1	0.00	91.21
Totals	105,743	100.00	100.00

[a] One ADS represents six 25 cent ordinary shares.

[b] One holder of ADSs represents 792,838 underlying shareholders.

As at 31 December 2012, there were also 1,544 preference shareholders. Preference shareholders represented 0.44% and ordinary shareholders represented 99.56% of the total issued nominal share capital of the company (excluding shares held in treasury) as at that date.

In accordance with DTR 5, we have received notification that as at 31 December 2012 BlackRock, Inc. held 5.43 %, The Capital Group Companies, Inc. held 3.76% and Legal & General Group Plc held 3.75% of the voting rights of the issued share capital of the company. As at 19 February 2013 BlackRock, Inc. held 5.39%, The Capital Group Companies, Inc. held 3.88% and Legal & General Group Plc held 3.82% of the voting rights of the issued share capital of the company.

Under the US Securities Exchange Act of 1934 we have received notification of the following interests as at 19 February 2013:

Holder	Holding of ordinary shares	Percentage of ordinary share capital excluding shares held in treasury
JPMorgan Chase Bank N.A., depositary for ADSs, through its nominee Guaranty Nominees Limited	5,183,195,517	27.05
BlackRock, Inc.	1,032,851,797	5.39

The company's major shareholders do not have different voting rights.

The company has also been notified of the following interests in preference shares as at 19 February 2013:

Holder	Holding of 8% cumulative first preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society	945,000	13.07
M & G Investment Management Ltd.	528,150	7.30
Barclays Wealth	430,894	5.96
Smith & Williamson Investment Management Ltd.	405,350	5.60
Duncan Lawrie Ltd.	395,876	5.47

Holder	Holding of 9% cumulative second preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society	987,000	18.03
M & G Investment Management Ltd.	644,450	11.77
Royal London Asset Management Ltd.	388,000	7.09
Smith & Williamson Investment Management Ltd.	385,500	7.04

Lazard Asset Management Limited disposed of its interests in 374,000 8% cumulative first preference shares and 404,500 9% cumulative second preference shares during 2011.

Gartmore Investment Management Limited disposed of its interest in 394,538 8% cumulative first preference shares and 500,000 9% cumulative second preference shares during 2010.

In accordance with DTR 5.8.12, The Capital Group of Companies, Inc. notified the company on 24 September 2012 that due to their group reorganization their holdings would not be reported separately but as a combined holdings thereby taking their interest in shares above the 3% threshold as of 1 September 2012.

As at 19 February 2013, the total preference shares in issue comprised only 0.44% of the company's total issued nominal share capital (excluding shares held in treasury), the rest being ordinary shares.

Purchases of equity securities by the issuer and affiliated purchasers

At the AGM on 12 April 2012, authorization was given to repurchase up to 1.9 billion ordinary shares in the period to the next AGM in 2013 or 12 July 2013, 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 2012 to 19 February 2013.

The following table provides details of ordinary share purchases made by Employee Share Ownership Plans (ESOPs) and other purchases of ordinary shares and ADSs made to satisfy the requirements of certain employee share-based payment plans.

	Total number of shares purchased	Average 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]
2012				
January	**Nil**			
February	**Nil**			
March	**2,926,611**	**7.95**		
April	**130**	**7.77**		
May	**273**	**7.54**		
June	**1,200,000**	**6.12**		
July	**68**	**6.56**		
August	**970,365**	**7.28**		
September	**2,936,447**	**6.95**		
October	**5,790,900**	**7.23**		
November	**30,931,671**	**7.12**		
December	**Nil**			
2013[b]				
January	**Nil**			
February (to 19 February)	**Nil**			

[a] No shares were repurchased pursuant to a publicly announced plan. Transactions represent the purchase of ordinary shares by ESOPs and other purchases of ordinary shares and ADSs made to satisfy requirements of certain employee share-based payment plans.

[b] The ESOPs did not purchase any shares in the period 1 January 2013 to 19 February 2013. However, on 31 January 2013, 10 million shares were transferred from treasury shares to the ESOPs to satisfy expected option exercises under the BP Share Option Plan.

Fees and charges payable by ADSs holders

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 underlying shares	Issuance of ADSs against the deposit of shares, including 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.	$5.00 per 100 ADSs (or portion thereof) 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 that 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 more cash dividends or other cash distributions.

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 ADS 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 $3,233,241 for the year ended 31 December 2012.

The table below sets out the types of expenses that the Depositary has agreed to reimburse and the fees it has agreed to waive for standard costs associated with the administration of the ADS programme relating to the year ended 31 December 2012. The Depositary has also paid certain expenses directly to third parties on behalf of the company.

Category of expense reimbursed, waived or paid directly to third parties	Amount reimbursed, waived or paid directly to third parties for the year ended 31 December 2012
NYSE listing fees reimbursed	$431,034
Service fees and out of pocket expenses waived[a]	$1,825,248
Broker fees reimbursed[b]	$852,609
Other third-party mailing costs reimbursed[c]	$124,350
Total	$3,233,241

[a] Includes fees in relation to transfer agent costs and costs of the BP Scrip Dividend Programme operated by JPMorgan Chase Bank, N.A.

[b] Broker reimbursements are fees payable to Broadridge 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.

[c] Payment of fees to Precision IR for proxy solicitation and investor support.

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.

Documents on display

BP Annual Report and Form 20-F 2012 is also available online at *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 via an email request addressed to *bpdistributionservices@bp.com* or from Precision IR at +1 888 301 2505 or via an email request addressed to *bpreports@precisionir.com* if in the 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. In addition, BP's SEC filings are available to the public at the SEC's website. BP discloses on its website at *bp.com/NYSEcorporategovernancerules*, and in this report (see Corporate governance practices (Form 20-F Item 16G) on page 148) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

Administration

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payments or the Scrip Dividend Programme or to change the way you receive your company documents (such as the *BP Annual Report and Form 20-F, BP Summary Review* and *Notice of BP Annual General Meeting*) please contact the BP Registrar or the BP ADS Depositary.

Ordinary and preference shareholders

Capita Registrars
The Registry, 34 Beckenham Road
Beckenham, Kent, BR3 4TU, UK
Freephone in UK 0800 701107
From outside the UK +44 (0)20 3170 3678

Textphone 0871 664 0532; fax +44 (0)1484 600512

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.

ADS holders

JPMorgan Chase Bank, N.A.
PO Box 64504
St Paul, MN 55164-0504, US
Toll-free in US and Canada +1 877 638 5672
From outside the US and Canada +1 651 306 4383

Annual general meeting

The 2013 AGM will be held on Thursday, 11 April 2013 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 for 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 the *Notice of BP Annual General Meeting 2013*.

By order of the board
David J Jackson
Company Secretary
6 March 2013

BP p.l.c.
Registered in England and Wales No. 102498

Additional disclosures

Legal proceedings

Proceedings relating to the Deepwater Horizon oil spill

BP p.l.c., BP Exploration & Production Inc. (BPXP) and various other BP entities (collectively referred to as BP) are among the companies named as defendants in approximately 750 civil lawsuits resulting from the 20 April 2010 explosions and fire on the semi-submersible rig Deepwater Horizon and resulting oil spill (the Incident) and further actions are likely to be brought. BPXP is lease operator of Mississippi Canyon, Block 252 in the Gulf of Mexico (Macondo), where the Deepwater Horizon was deployed at the time of the Incident. The other working interest owners at the time of the Incident were Anadarko Petroleum Company (Anadarko) and MOEX Offshore 2007 LLC (MOEX). The Deepwater Horizon, which was owned and operated by certain affiliates of Transocean Ltd. (Transocean), sank on 22 April 2010. The pending lawsuits and/or claims arising from the Incident have generally been brought in US federal and state courts. Plaintiffs include individuals, corporations, insurers, and governmental entities and many of the lawsuits purport to be class actions. The lawsuits assert, among others, claims for personal injury in connection with the Incident itself and the response to it, wrongful death, commercial and economic injury, breach of contract and violations of statutes. The lawsuits seek various remedies including compensation to injured workers and families of deceased workers, recovery for commercial losses and property damage, compensation for personal injuries and medical monitoring, claims for environmental damage, remediation costs, claims for unpaid wages, injunctive and declaratory relief, treble damages and punitive damages. Purported classes of claimants include residents of the states of Louisiana, Mississippi, Alabama, Florida, Texas, Tennessee, Kentucky, Georgia and South Carolina; property owners and rental agents, fishermen and persons dependent on the fishing industry, charter boat owners and deck hands, marina owners, gasoline distributors, shipping interests, restaurant and hotel owners, cruise lines and others who are property and/or business owners alleged to have suffered economic loss; and response workers and residents claiming injuries due to exposure to the components of oil and/or chemical dispersants. Among other claims arising from the spill response efforts, lawsuits have been filed claiming that additional payments are due by BP under certain Master Vessel Charter Agreements entered into in the course of the Vessels of Opportunity Program implemented as part of the response to the Incident. Purported class action and individual lawsuits have also been filed in US state and federal courts, as well as one suit in Canada, against BP entities and/or various current and former officers and directors alleging, among other things, shareholder derivative claims, securities fraud claims, violations of the Employee Retirement Income Security Act (ERISA) and contractual and quasi-contractual claims related to the cancellation of the dividend on 16 June 2010. In August 2010, many of the lawsuits pending in federal court were consolidated by the Federal Judicial Panel on Multi-district Litigation into two multi-district litigation proceedings, one in federal court in Houston for the securities, derivative, ERISA and dividend cases and another in federal court in New Orleans for the remaining cases.

BP has had discussions with the DoJ regarding possible settlements of the claims by the DoJ, other federal agencies and certain States, in whole or in part, and remains open to further discussions but there are a number of significant issues and considerable uncertainty as to whether any agreement could ultimately be reached.

On 25 February 2013, the first phase of a Trial of Liability, Limitation, Exoneration and Fault Allocation commenced in the federal multi-district litigation proceeding in New Orleans. For further information, see page 164 below.

In addition, BP has been named in several lawsuits alleging claims under the Racketeer-Influenced and Corrupt Organizations Act (RICO). On 15 July 2011, the judge granted BP's motion to dismiss a master complaint raising RICO claims against BP. The court's order dismissed the claims of the plaintiffs in four RICO cases encompassed by the master complaint.

On 26 August 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted in part BP's motion to dismiss a master complaint raising claims for economic loss by private plaintiffs, dismissing plaintiffs' state law claims and limiting the types of maritime law claims plaintiffs may pursue, but also held that certain classes of claimants may seek punitive damages under general maritime law. The judge did not, however, lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply his dismissal of the master complaint to those individual complaints. On 30 September 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted in part BP's motion to dismiss a master complaint asserting personal injury claims on behalf of persons exposed to crude oil or chemical dispersants, dismissing plaintiffs' state law claims, claims by seamen for punitive damages, claims for medical monitoring damages by asymptomatic plaintiffs, claims for battery and nuisance under maritime law, and claims alleging negligence per se. As with his other rulings on motions to dismiss master complaints, the judge did not lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply his dismissal of the master complaint to those individual complaints.

Shareholder derivative lawsuits related to the Incident have been filed in US federal and state courts against various current and former officers and directors of BP alleging, among other things, breach of fiduciary duty, gross mismanagement, abuse of control and waste of corporate assets. On 15 September 2011, the judge in the federal multi-district litigation proceeding in Houston (MDL 2185) granted BP's motion to dismiss the consolidated shareholder derivative litigation pending there on the grounds that the courts of England are the appropriate forum for the litigation. On 8 December 2011, a final judgment was entered dismissing the shareholder derivative case and, on 3 January 2012, one of the derivative plaintiffs filed a notice of appeal to the US Court of Appeals for the Fifth Circuit. On 16 January 2013, the Court of Appeals affirmed dismissal of the action. The plaintiffs in the two remaining state-court actions, which are pending in Texas and Louisiana, have agreed to be bound by the outcome of the federal case.

On 13 February 2012, the judge in the federal multi-district litigation proceeding in Houston issued two decisions on the defendants' motions to dismiss the two consolidated securities fraud complaints filed on behalf of purported classes of BP ordinary shareholders and ADS holders. In those decisions the court dismissed all of the claims of the ordinary shareholders, dismissed the claims of the lead class of ADS holders against most of the individual defendants while holding that a subset of the claims against two individual defendants and the corporate defendants could proceed, and dismissed all of the claims of a smaller purported subclass with leave to re-plead in 20 days. On 2 April 2012, plaintiffs in the lead class and subclass filed an amended consolidated complaint with claims based on (1) the 12 alleged misstatements that the court held were actionable in its February 2012 order on BP's motion to dismiss the earlier complaints; and (2) 13 alleged misstatements concerning BP's operating management system that the judge either rejected with leave to re-plead or did not address in his February decisions. On 2 May 2012, defendants moved to dismiss the claims based on the 13 statements in the amended complaint that the judge did not already rule are actionable. On 6 February 2013, the judge granted in part this motion to dismiss, rejecting plaintiffs' claims based on 10 of the 17 statements at issue in the motion and also dismissing all claims against Andrew Inglis. On 5 March 2013, the court announced that a trial date has been scheduled for 25 August 2014.

In April and May 2012, six new cases (three of which were consolidated into one action) were filed in state and federal courts by one or more state, county or municipal pension funds against BP entities and several current and former officers and directors seeking damages for alleged losses those funds suffered because of their purchases of BP ordinary shares and, in two cases, ADSs. The funds assert various state law and federal law claims. All of the cases have been transferred to the judge in the federal multi-district litigation proceeding in Houston. In May and June, plaintiffs in the two cases that were filed in state court moved to send those cases back to state court, which was denied on 3 October 2012. On 4 January 2013, the judge denied a motion to certify that decision for immediate appeal. On 21 December 2012, defendants filed motions to dismiss these cases. From July 2012 to January 2013, nine additional cases were filed in Texas state and federal courts (four of which were consolidated into one action) by pension or investment funds against BP entities and current and former officers, asserting Texas state law claims and seeking damages for alleged losses that those funds suffered because of their purchases of BP ordinary shares. All of the cases have been transferred to federal court in Houston, and it is anticipated that they will be handled by the same judge presiding over the multi-district litigation proceeding.

On 20 July 2012, a BP entity received an amended statement of claim for an action in Alberta, Canada, filed by three plaintiffs seeking to assert claims under Canadian law against BP on behalf of a class of Canadian residents who allegedly suffered losses because of their purchase of BP ordinary shares and ADSs. This case was dismissed on jurisdictional grounds on 14 November 2012. On 15 November 2012, one of the plaintiffs re-filed a statement of claim against BP in Ontario, Canada, seeking to assert the same claims under Canadian law against BP on behalf of a class of Canadian residents. BP informed the Ontario court that it intends to contest jurisdiction, and a hearing on this issue has been scheduled for 23-24 September 2013.

On 5 July 2012, the judge in the federal multi-district litigation proceeding in Houston (MDL 2185) issued a decision granting the defendants' motions to dismiss, for lack of personal jurisdiction, the lawsuit against BP p.l.c. for cancelling its dividend payment in June 2010. On 10 August 2012, the plaintiffs filed an amended complaint, which BP moved to dismiss on 9 October 2012.

On 30 March 2012, the judge in the federal multi-district litigation proceeding in Houston (MDL 2185) issued a decision granting the defendants' motions to dismiss the ERISA case related to BP share funds in several employee benefit savings plans. On 11 April 2012, plaintiffs requested leave to file an amended complaint, which was denied on 27 August 2012. Final judgment dismissing the case was entered on 4 September 2012 and, on 25 September 2012, plaintiffs filed a notice of appeal to the US Court of Appeals for the Fifth Circuit.

On 1 June 2010, the US Department of Justice (DoJ) announced that it was conducting an investigation into the Incident encompassing possible violations of US civil or criminal laws. The DoJ announced on 7 March 2011 that it had created a unified task force of federal agencies, led by the DoJ Criminal Division, to investigate the Incident. Other US federal agencies still may commence investigations relating to the Incident. The SEC and DoJ also investigated potential securities law violations, including potential securities fraud claims, alleged to have arisen in relation to the Incident. On 15 November 2012, BP announced that it reached agreement with the US government, subject to court approval, to resolve all federal criminal charges and all claims by the SEC against BP arising from the Deepwater Horizon accident, oil spill and response.

On 29 January 2013, the US District Court for the Eastern District of Louisiana accepted BP's pleas regarding the federal criminal charges, and BP was sentenced in connection with the criminal plea agreement. BP pleaded guilty to 11 felony counts of Misconduct or Neglect of Ships Officers relating to the loss of 11 lives; one misdemeanour count under the Clean Water Act; one misdemeanour count under the Migratory Bird Treaty Act; and one felony count of obstruction of Congress. The final judgment and order of the US District Court is provided as Exhibit 99.1 to this *Annual Report and Form 20-F 2012*.

Pursuant to that sentence, BP will pay $4 billion, including $1.256 billion in criminal fines, in instalments over a period of five years. Under the terms of the criminal plea agreement, a total of $2.394 billion will be paid to the National Fish & Wildlife Foundation (NFWF) over a period of five years. In addition, $350 million will be paid to the National Academy of Sciences (NAS) over a period of five years. The court also ordered, as previously agreed with the US government, that BP serve a term of five years' probation. Pursuant to the terms of the plea agreement, the court also ordered certain equitable relief, including additional actions, enforceable by the court, to further enhance the safety of drilling operations in the Gulf of Mexico. These requirements relate to BP's risk management processes, such as third-party auditing and verification, BP's Oil Spill Response Plan, training, and well control equipment and processes such as blowout preventers and cementing. BP has also agreed to maintain a real-time drilling operations monitoring centre in Houston or another appropriate location. In addition, BP will undertake several initiatives with academia and regulators to develop new technologies related to deepwater drilling safety. The resolution also provides for the appointment of two monitors, both with terms of four years. A process safety monitor will review, evaluate and provide recommendations for the improvement of BP's process safety and risk management procedures including, but not limited to, BP's risk review of processes concerning deepwater drilling in the Gulf of Mexico. An ethics monitor will review and provide recommendations for the improvement of BP's code of conduct and its implementation and enforcement. BP has also agreed to hire an independent third-party auditor who will review and report to the probation officer, the DoJ and BP regarding BP's implementation of key terms of the proposed settlement, including procedures and systems related to safety and environmental management, operational oversight, and oil spill response training and drills. Under the plea agreement, BP has also agreed to co-operate in ongoing criminal actions and investigations, including prosecutions of four former employees who have been separately charged.

In its resolution with the SEC, BP has resolved the SEC's Deepwater Horizon-related claims against the company under Sections 10(b) and 13(a) of the Securities Exchange Act of 1934 and the associated rules. BP has agreed to a civil penalty of $525 million, payable in three instalments over a period of three years, and has consented to the entry of an injunction prohibiting it from violating certain US securities laws and regulations. The SEC's claims are premised on oil flow rate estimates contained in three reports provided by BP to the SEC during a one-week period (on 29 and 30 April 2010 and 4 May 2010), within the first 14 days after the accident. BP's consent was incorporated in a final judgment and court order on 10 December 2012, and BP made its first payment of $175 million on 11 December 2012. BP's consent and the final judgment and order of the US District Court are provided as Exhibit 99.2 and Exhibit 99.3, respectively, to this *Annual Report and Form 20-F 2012*.

BP's November 2012 agreement with the US government does not resolve the DoJ's civil claims, such as claims for civil penalties under the Clean Water Act or claims for natural resource damages under the Oil Pollution Act of 1990 (OPA 90). Neither does it resolve the private securities claims pending in the multi-district litigation proceedings in Houston (MDL 2185).

On 28 November 2012, the US Environmental Protection Agency (EPA) notified BP that it had temporarily suspended BP p.l.c., BPXP and a number of other BP subsidiaries from participating in new federal contracts. As a result of the temporary suspension, the BP entities listed in the notice are ineligible to receive any US government contracts either through the award of a new contract, or the extension of the term of or renewal of an expiring contract. The suspension does not affect existing contracts the company has with the US government, including those relating to current and ongoing drilling and production operations in the Gulf of Mexico.

The charges to which BPXP pleaded guilty included one misdemeanour count under the Clean Water Act that, by operation of law following the court's acceptance of BPXP's plea, triggers a statutory debarment, also referred to as mandatory debarment, of the BPXP facility where the Clean Water Act violation occurred. On 1 February 2013, the EPA issued a notice that BPXP was mandatorily debarred at its Houston headquarters.

Mandatory debarment prevents a company from entering into new contracts or new leases with the US government that would be performed at the facility where the Clean Water Act violation occurred. A mandatory debarment does not affect any existing contracts or leases a company has with the US government and will remain in place until such time as the debarment is lifted through an agreement with the EPA.

With respect to the entities named in the temporary suspension, the temporary suspension may be maintained or the EPA may elect to issue a notice of proposed discretionary debarment to some or all of the named entities. Like suspension, a discretionary debarment would preclude BP entities listed in the notice from receiving new federal fuel contracts, as well as new oil and gas leases, although existing contracts and leases will continue. Discretionary debarment typically lasts three to five years and may be imposed for a longer period, unless it is resolved through an administrative agreement. To date, the EPA has not issued such notice of proposed discretionary debarment to any of the entities named in the temporary suspension.

While BP's discussions with the EPA have been taking place in parallel to the court proceedings on the criminal plea, the company's work toward reaching an administrative agreement with the EPA is a separate process, and it may take some time to resolve issues relating to such an agreement. BPXP's mandatory debarment applies following sentencing and is not an indication of any change in the status of discussions with the EPA. The process for resolving both mandatory and discretionary debarment is essentially the same as for resolving the temporary suspension. BP continues to work with the EPA in preparing an administrative agreement that will resolve suspension and debarment issues. On 15 February 2013, BP filed an administrative challenge with the EPA seeking to lift the 28 November 2012 suspension of 22 BP entities and the 1 February 2013 statutory debarment of BPXP at its Houston headquarters. BP maintains that the EPA's actions do not reflect BP's present status as a responsible government contractor. The EPA will review the administrative record and determine whether to change its decision. Decisions reached by the EPA can be challenged in federal court.

The United States filed a civil complaint in the multi-district litigation proceeding in New Orleans against BPXP and others on 15 December 2010 (DoJ Action). The complaint seeks a declaration of liability under OPA 90 and civil penalties under the Clean Water Act and sets forth a purported reservation of rights on behalf of the US to amend the complaint or file additional complaints seeking various remedies under various US federal laws and statutes. See Financial statements – Note 2 on page 194.

A Trial of Liability, Limitation, Exoneration, and Fault Allocation was originally scheduled to begin in the federal multi-district litigation proceeding in New Orleans in February 2012. The court's pre-trial order issued 14 September 2011 provided for the trial to proceed in three phases and to include issues asserted in or relevant to the claims, counterclaims, cross-claims, third-party claims, and comparative fault defences raised in Transocean's Limitation of Liability Action (discussed below). Pursuant to an amended pre-trial order dated 30 May 2012, the first phase of the Trial of Liability, Limitation, Exoneration, and Fault Allocation commenced on 25 February 2013. The first trial phase will address issues arising out of the conduct of various parties allegedly relevant to the loss of well control at the Macondo well, the ensuing fire and explosion on the Deepwater Horizon on 20 April 2010, the sinking of the vessel on 22 April 2010 and the initiation of the release of oil from the Deepwater Horizon or the Macondo well during those time periods, including whether BP or any other party was grossly negligent. The second trial phase, which is projected to commence in September 2013, will address (i) "source control" issues pertaining to the conduct or inaction of BP, Transocean or other relevant parties regarding stopping the release of hydrocarbons stemming from the Incident from 22 April 2010 through approximately 19 September 2010, and (ii) "quantification of discharge" issues pertaining to the amount of oil actually released into the Gulf of Mexico as a result of the Incident from the time when these releases began until the Macondo well was capped on approximately 15 July 2010 and then permanently cemented shut on approximately 19 September 2010.

On 20 April 2011, BP filed claims against Cameron International Corporation (Cameron), Halliburton Energy Services, Inc. (Halliburton), and Transocean in the DoJ Action, seeking contribution for any assessments against BP under OPA 90 based on those entities' fault. On 20 June 2011, Cameron and Halliburton moved to dismiss BP's claims against them in the DoJ Action. BP's claim against Cameron has been resolved pursuant to settlement, but Halliburton's motion remains pending.

On 30 May 2011, Transocean filed claims against BP in the DoJ Action alleging that BP America Production Company had breached its contract with Transocean Holdings LLC by not agreeing to indemnify Transocean against liability related to the Incident. Transocean also asserted claims against BP under state law, maritime law and OPA 90 for contribution. On 20 June 2011, Cameron filed similar claims against BP in the DoJ Action.

On 8 December 2011, the United States brought a motion for partial summary judgment seeking, among other things, an order finding that BP, Transocean and Anadarko are strictly liable for a civil penalty under Section 311(b) (7)(A) of the Clean Water Act. On 22 February 2012, the judge ruled on motions filed in the DoJ Action by the United States, Anadarko, and Transocean seeking early rulings regarding the liability of BP, Anadarko and Transocean under OPA 90 and the Clean Water Act, but limited the order to addressing the discharge of hydrocarbons occurring under the surface of the water. Regarding OPA 90, the judge held that BP and Anadarko are responsible parties under OPA 90 with regard to the subsurface discharge. The judge ruled that BP and Anadarko have joint and several liability under OPA 90 for removal costs and damages for such discharge, but did not rule on whether such liability under OPA 90 is unlimited. While the judge held that Transocean is not a responsible party under OPA 90 for subsurface discharge, the judge left open the question of whether Transocean may be liable under OPA 90 for removal costs for such discharge as the owner/operator of the Deepwater Horizon. Regarding the Clean Water Act, the judge held that the subsurface discharge was from the Macondo well, rather than from the Deepwater Horizon, and that BP and Anadarko are liable for civil penalties under Section 311 of the Clean Water Act as owners of the well. The judge left open the question of whether Transocean may be liable under the Clean Water Act as an operator of the Macondo well. Anadarko, BP and the United States have each appealed the 22 February 2012 ruling to the US Court of Appeals for the Fifth Circuit, and the appeals have been consolidated. On 23 October 2012, Transocean filed a motion to dismiss the appeal as untimely and for lack of jurisdiction. On 5 February 2013, the appeals court denied Transocean's motion.

On 11 January 2013, BP filed a motion for partial summary judgment against the United States, seeking rulings that (1) BP collected at least 810,000 barrels from the broken riser, from the top of the blowout preventer and lower marine riser package, and from the choke and kill lines of the blowout preventer, all before these barrels reached the waters of the Gulf of Mexico, and (2) that these barrels may not be counted toward the maximum penalty potentially to be assessed against BP under Section 311 of the Clean Water Act, 33 U.S.C. § 1321. The court set a schedule under which briefing on BP's motion will be complete in February 2013. On 15 February 2013, BP and the United States reached a stipulation, entered by the court on 19 February 2013. The stipulation provides that 810,000 barrels of oil were collected without coming into contact with ambient Gulf waters and that those 810,000 barrels of oil are not to be used in calculating the statutory maximum penalty under the Clean Water Act.

On 1 March 2013, Transocean sought the MDL 2179 court's leave to supplement its pleadings to include an affirmative defence asserting that BP's representations regarding the flow rate at the Macondo well constituted an intervening and superseding cause of the oil spill for the majority of its duration. Transocean's defence claims that BP fraudulently misrepresented and concealed information regarding the flow rate at the Macondo well in late April and May 2010, as well as the likelihood of success of a top-kill approach to stopping the flow of hydrocarbons from the well, and thus prevented the implementation of alternative means of source control that Transocean asserts could have capped the well as early as May 2010. Also on 1 March 2013, Halliburton filed a motion for leave to amend its answers in MDL 2179 to assert a similar defence.

On 4 April 2011, BP initiated contractual out-of-court dispute resolution proceedings against Anadarko and MOEX, claiming that they have breached the parties' contract by failing to reimburse BP for their working-interest share of Incident-related costs. On 19 April 2011, Anadarko filed a cross-claim against BP, alleging gross negligence and 15 other counts under state and federal laws. Anadarko sought a declaration that it was excused from its contractual obligation to pay Incident-related costs. Anadarko also sought damages from alleged economic losses and contribution or indemnity for claims filed against it by other parties. On 20 May 2011, BP and MOEX announced a settlement agreement of all claims between them, including a cross-claim brought by MOEX on 19 April 2011 similar to the Anadarko claim. Under the settlement agreement, MOEX has paid BP $1.065 billion, which BP has applied towards the $20-billion Trust, and has also agreed to transfer all of its 10% interest in the MC252 lease to BP. On 17 October 2011, BP and Anadarko announced that they had reached a final agreement to settle all claims between the companies related to the Incident, including mutual releases of all claims between BP and Anadarko that are subject to the contractual out-of-court dispute resolution proceedings or the federal multi-district litigation proceeding in New Orleans. Under the settlement agreement, Anadarko has paid BP $4 billion, which BP has applied towards the $20-billion Trust, and has also agreed to transfer all of its 25% interest in the MC252 lease to BP. The settlement agreement also grants Anadarko the opportunity for a 12.5% participation in certain future recoveries from third parties and certain insurance proceeds in the event that such recoveries and proceeds exceed $1.5 billion in aggregate. Any such payments to Anadarko are capped at a total of $1 billion. BP has agreed to indemnify Anadarko and MOEX for certain claims arising from the Incident (excluding civil, criminal or administrative fines and penalties, claims for punitive damages, and certain other claims). The settlement agreements with Anadarko and MOEX are not an admission of liability by any party regarding the Incident.

On 18 February 2011, Transocean filed a third-party complaint against BP, the US government, and other corporations involved in the Incident, naming those entities as formal parties in its Limitation of Liability action pending in federal court in New Orleans.

On 20 April 2011, Transocean filed claims in its Limitation of Liability action alleging that BP had breached BP America Production Company's contract with Transocean Holdings LLC by BP not agreeing to indemnify Transocean against liability related to the Incident and by not paying certain invoices. Transocean also asserted claims against BP under state law, maritime law, and OPA 90 for contribution. On 1 November 2011, Transocean filed a motion for partial summary judgment on certain claims filed in the Limitation Action and the DoJ Action between BP and Transocean. Transocean's motion sought an order that would bar BP's contribution claims against Transocean and require BP to defend and indemnify Transocean against all pollution claims, including those resulting from any gross negligence, and from civil fines and penalties sought by the government. On 7 December 2011, BP filed a cross-motion for summary judgment seeking an order that BP is not required to indemnify Transocean for any civil fines and penalties sought by the government or for punitive damages.

On 26 January 2012, the judge ruled on BP's and Transocean's indemnity motions, holding that BP is required to indemnify Transocean for third-party claims for compensatory damages resulting from pollution originating beneath the surface of the water, regardless of whether the claim results from Transocean's strict liability, negligence or gross negligence. The court, however, ruled that BP does not owe Transocean indemnity for such claims to the extent Transocean is held liable for punitive damages or for civil penalties under the Clean Water Act, or if Transocean acted with intentional or wilful misconduct in excess of gross negligence. The court further held that BP's obligation to defend Transocean for third-party claims does not require BP to fund Transocean's defence of third-party claims at this time, nor does it include Transocean's expenses in proving its right to indemnity. The court deferred a final ruling on the question of whether Transocean breached its drilling contract with BP so as to invalidate the contract's indemnity clause.

On 20 April 2011, Halliburton filed claims in Transocean's Limitation of Liability action seeking indemnification from BP for claims brought against Halliburton in that action, and Cameron asserted claims against BP for contribution under state law, maritime law and OPA 90, as well as for contribution on the basis of comparative fault. Halliburton also asserted a claim for negligence, gross negligence and wilful misconduct against BP and others. On 19 April 2011, Halliburton filed a separate lawsuit in Texas state court seeking indemnification from BPXP for certain tort and pollution-related liabilities resulting from the Incident. On 3 May 2011, BPXP removed Halliburton's case to federal court, and on 9 August 2011, the action was transferred to the federal multi-district litigation proceedings pending in New Orleans.

Subsequently, on 30 November 2011, Halliburton filed a motion for summary judgment in the federal multi-district litigation proceedings pending in New Orleans. Halliburton's motion sought an order stating that Halliburton is entitled to full and complete indemnity, including payment of defence costs, from BP for claims related to the Incident and denying BP's claims seeking contribution against Halliburton. On 21 December 2011, BP filed a cross-motion for partial summary judgment seeking an order that BP has no contractual obligation to indemnify Halliburton for fines, penalties or punitive damages resulting from the Incident.

On 31 January 2012, the judge ruled on BP's and Halliburton's indemnity motions, holding that BP is required to indemnify Halliburton for third-party claims for compensatory damages resulting from pollution that did not originate from property or equipment of Halliburton located above the surface of the land or water, regardless of whether the claims result from Halliburton's gross negligence. The court, however, ruled that BP does not owe Halliburton indemnity to the extent that Halliburton is held liable for punitive damages or for civil penalties under the Clean Water Act. The court further held that BP's obligation to defend Halliburton for third-party claims does not require BP to fund Halliburton's defence of third-party claims at this time, nor does it include Halliburton's expenses in proving its right to indemnity. The court deferred ruling on whether BP is required to indemnify Halliburton for any penalties or fines under the Outer Continental Shelf Lands Act. It also deferred ruling on whether Halliburton acted so as to invalidate the indemnity by breaching its contract with BP, by committing fraud, or by committing another act that materially increased the risk to BP or prejudiced the rights of BP as an indemnitor.

On 1 September 2011, Halliburton filed an additional lawsuit against BP in Texas state court. Its complaint alleges that BP did not identify the existence of a purported hydrocarbon zone at the Macondo well to Halliburton in connection with Halliburton's cement work performed before the Incident and that BP has concealed the existence of this purported hydrocarbon zone following the Incident. Halliburton claims that the alleged failure to identify this information has harmed its business ventures and reputation and resulted in lost profits and other damages. On 16 September 2011, BP removed the action to federal court, where it was stayed until it was transferred by the Judicial Panel on Multidistrict Litigation to the multi-district litigation proceeding in New Orleans. On 1 September 2011, Halliburton also moved to amend its claims in Transocean's Limitation of Liability action to add claims for fraud based on similar factual allegations to those included in its 1 September 2011 lawsuit against BP in Texas state court. On 11 October 2011, the magistrate judge in the federal multi-district litigation proceeding in New Orleans denied Halliburton's motion to amend its claims, and Halliburton's motion to review the order was denied by the judge on 19 December 2011.

On 20 April 2011, BP asserted claims against Cameron, Halliburton and Transocean in the Limitation of Liability action. BP's claims against Transocean include breach of contract, unseaworthiness of the Deepwater Horizon vessel, negligence (or gross negligence and/or gross fault as may be established at trial based upon the evidence), contribution and subrogation for costs (including those arising from litigation claims) resulting from the Incident, as well as a declaratory claim that Transocean is wholly or partly at fault for the Incident and responsible for its proportionate share of the costs and damages. BP asserted claims against Halliburton for fraud and fraudulent concealment based on Halliburton's misrepresentations to BP concerning, among other things, the stability testing on the foamed cement used at the Macondo well; for negligence (or, if established by the evidence at trial, gross negligence) based on Halliburton's performance of its professional services, including cementing and mud logging services; and for contribution and subrogation for amounts that BP has paid in responding to the Incident, as well as in OPA assessments and in payments to plaintiffs. BP filed a similar complaint in federal court in the Southern District of Texas, Houston Division, against Halliburton, and the action was transferred on 4 May 2011 to the federal multi-district litigation proceeding pending in New Orleans.

On 16 December 2011, BP and Cameron announced their agreement to settle all claims between the companies related to the Incident, including mutual releases of claims between BP and Cameron that are subject to the federal multi-district litigation proceeding in New Orleans. Under the settlement agreement, Cameron has paid BP $250 million in cash in January 2012, which BP has applied towards the $20-billion Trust. BP has agreed to indemnify Cameron for compensatory claims arising from the Incident, including claims brought relating to pollution damage or any damage to natural resources, but excluding civil, criminal or administrative fines and penalties, claims for punitive damages, and certain other claims.

On 20 May 2011, Dril-Quip, Inc. and M-I L.L.C. (M-I) filed claims against BP in Transocean's Limitation of Liability action, each claiming a right to contribution from BP for damages assessed against them as a result of the Incident, based on allegations of negligence. M-I also claimed a right to indemnity for such damages based on its well services contracts with BP. On 20 June 2011, BP filed counter-complaints against Dril-Quip, Inc. and M-I, asking for contribution and subrogation based on those entities' fault in connection with the Incident and under OPA 90, and seeking declaratory judgment that Dril-Quip, Inc. and M-I caused or contributed to, and are responsible in whole or in part for damages incurred by BP in relation to the Incident. On 20 January 2012, the court granted Dril-Quip, Inc.'s motion for summary judgment, dismissing with prejudice all claims asserted against Dril-Quip in the federal multi-district litigation proceeding in New Orleans.

On 21 January 2012, BP and M-I entered into an agreement settling all claims between the companies related to the Incident, including mutual releases of claims between BP and M-I that are subject to the federal multi-district litigation proceeding in New Orleans. Under the settlement agreement, M-I has agreed to indemnify BP for personal injury and death claims brought by M-I employees. BP has agreed to indemnify M-I for claims resulting from the Incident, but excluding certain claims.

On 14 September 2011, the US Coast Guard and Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) issued a report (BOEMRE Report) regarding the causes of the 20 April 2010 Macondo well blowout. The BOEMRE Report states that decisions by BP, Halliburton and Transocean increased the risk or failed to fully consider or mitigate the risk of a blowout on 20 April 2010. The BOEMRE Report also states that BP, Transocean and Halliburton violated certain regulations related to offshore drilling. In itself, the BOEMRE Report does not constitute the initiation of enforcement proceedings relating to any violation. On 12 October 2011, the U.S. Department of the Interior Bureau of Safety and Environmental Enforcement issued to BPXP, Transocean, and Halliburton Notification of Incidents of Noncompliance (INCs). The notification issued to BPXP is for a number of alleged regulatory violations concerning Macondo well operations. The Department of Interior has indicated that this list of violations may be supplemented as additional evidence is reviewed, and on 7 December 2011, the Bureau of Safety and Environmental Enforcement issued to BPXP a second INC. This notification was issued to BP for five alleged violations related to drilling and abandonment operations at the Macondo well. BP has filed an administrative appeal with respect to the first and second INCs. BP has filed a joint stay of proceedings with the Department of Interior with respect to both INCs.

On 18 October 2011, Cameron filed a petition for writ of mandamus with US Court of Appeals for the Fifth Circuit seeking an order vacating the trial plan for the 27 February 2012 trial and requiring that all claims against Cameron in that proceeding be tried before a jury. On 26 December 2011, the Court of Appeals denied the application for mandamus.

The State of Alabama has filed a lawsuit seeking damages for alleged economic and environmental harms, including natural resource damages, civil penalties under state law, declaratory and injunctive relief, and punitive damages as a result of the Incident. The State of Louisiana has filed a lawsuit to declare various BP entities (as well as other entities) liable for removal costs and damages, including natural resource damages under federal and state law, to recover civil penalties, attorney's fees, and response costs under state law, and to recover for alleged negligence, nuisance, trespass, fraudulent concealment and negligent misrepresentation of material facts regarding safety procedures and BP's (and other defendants') ability to manage the oil spill, unjust enrichment from economic and other damages to the State of Louisiana and its citizens, and punitive damages. The Louisiana Department of Environmental Quality has issued an administrative order seeking environmental civil penalties and other relief under state law. On 23 September 2011, BP removed this matter to federal district court, and it has been consolidated with the multi-district proceedings in New Orleans.

District Attorneys of 11 parishes in the State of Louisiana have filed suits under state wildlife statutes seeking penalties for damage to wildlife as a result of the spill. On 10 December 2010, the Mississippi Department of Environmental Quality issued a Complaint and Notice of Violation alleging violations of several state environmental statutes.

On 14 November 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted in part BP's motion to dismiss the complaints filed by the States of Alabama and Louisiana. The judge's order dismissed the States' claims brought under state law, including claims for civil penalties and the State of Louisiana's request for a declaratory judgment under the Louisiana Oil Spill Prevention and Response Act, holding that those claims were pre-empted by federal law. It also dismissed the State of Louisiana's claims of nuisance and trespass under general maritime law. The judge's order further held that the States have stated claims for negligence and products liability under general maritime law, that the States have sufficiently alleged presentment of their claims under OPA 90, and that the States may seek punitive damages under general maritime law. On 9 December 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted in part BP's motion to dismiss a master complaint brought on behalf of local government entities. The judge's order dismissed plaintiffs' state law claims and limited the types of maritime law claims plaintiffs may pursue, but also held that the plaintiffs have sufficiently alleged presentment of their claims under OPA 90 and that certain local government entity claimants may seek punitive damages under general maritime law. The judge did not, however, lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply his dismissal of the master complaint to those individual complaints.

In January 2013, the States of Alabama, Mississippi and Florida formally presented their claims to BP under OPA 90 for alleged losses including economic losses and property damage as a result of the Gulf of Mexico oil spill. BP is evaluating these claims. The State of Louisiana has also asserted similar claims. The amounts claimed, certain of which include punitive damages or other multipliers, are very substantial. However, BP considers the methodologies used to calculate these claims to be seriously flawed, not supported by the legislation and to substantially overstate the claims. Claims have also been presented by various local governments which are substantial in aggregate and more claims are expected to be presented. The amounts alleged in the presentments for State and Local government claims total over $34 billion. BP will defend vigorously against these claims if adjudicated at trial.

On 9 December 2011 and 28 December 2011, the judge in the federal multi-district litigation proceeding in New Orleans also granted BP's motions to dismiss complaints filed by the District Attorneys of 11 parishes in the State of Louisiana seeking penalties for damage to wildlife, holding that those claims are pre-empted by the Clean Water Act. All 11 of the District Attorneys of parishes in the State of Louisiana have now filed notices of appeal. The State of Alabama's attempt to intervene into the case has been denied. Since May 2012, amicus briefs have been filed in those appeals by the States of Alabama, Louisiana, and Mississippi. The appeal is now fully briefed and was scheduled for oral argument on 5 March 2013.

On 3 March 2012, BP announced an agreement in principle with the Plaintiffs' Steering Committee (PSC) in the federal multi-district litigation proceedings pending in the federal district court in New Orleans (MDL 2179) to settle the substantial majority of legitimate private economic and property damages claims and exposure-based medical claims stemming from the Incident. On 18 April 2012, BP and the PSC filed with that court the Economic and Property Damages Settlement Agreement and the Medical Benefits Class Action Settlement Agreement.

The Economic and Property Damages Settlement resolves certain economic and property damage claims, and the Medical Benefits Class Action Settlement resolves medical claims by response workers and certain Gulf Coast residents. The Economic and Property Damages Settlement includes a $2.3-billion BP commitment to help resolve economic loss claims related to the Gulf seafood industry and a $57-million fund to support continued advertising that promotes Gulf Coast tourism. It also resolves property damage in certain areas along the Gulf Coast, as well as claims for additional payments under certain Master Vessel Charter Agreements entered into in the course of the Vessels of Opportunity Program implemented as part of the response to the Incident. The Economic and Property Damages Settlement does not include claims made against BP by the DoJ or other federal agencies (including under the Clean Water Act and for Natural Resource Damages under the Oil Pollution Act) or by the states and local governments. Also excluded are certain other claims against BP, such as securities and shareholder claims pending in MDL 2185, and claims based solely on the deepwater drilling moratorium and/or the related permitting process.

The Medical Benefits Class Action Settlement involves payments to qualifying class members based on a matrix for certain Specified Physical Conditions, as well as a 21-year Periodic Medical Consultation Programme for qualifying class members. Although claims will not be paid until the agreement's Effective Date – *i.e.*, the final approval of the Medical Benefits Class Action Settlement and resolution of all appeals – class members are permitted to file claim forms in advance of the Effective Date to facilitate administration of the Medical Benefits Class Action Settlement upon the Effective Date. It also provides that class members claiming Later-Manifested Physical Conditions may pursue their claims through a mediation/litigation process, but waive, among other things, the right to seek punitive damages. Consistent with its commitment to the Gulf, BP has also agreed as part of the Medical Benefits Class Action Settlement to provide $105 million to the Gulf Region Health Outreach Program to improve the availability, scope and quality of healthcare in certain Gulf Coast communities. This healthcare outreach programme will be available to, and is intended to benefit, class members and other individuals in those communities.

Each agreement provides that class members will be compensated for their claims on a claims-made basis, according to agreed compensation protocols in separate court-supervised claims processes. The compensation protocols under the Economic and Property Damages Settlement provide for the payment of class members' economic losses and property damages. In addition many economic and property damages class members will receive payments based on negotiated risk transfer premiums (RTPs), which are multiplication factors designed, in part, to compensate claimants for potential future damages that are not currently known, relating to the Incident. The Economic and Property Damages Settlement and the Medical Benefits Class Action Settlement are not an admission of liability by BP. The settlements are uncapped except for economic loss claims related to the Gulf seafood industry under the Economic and Property Damages Settlement and the $105 million to be provided to the Gulf Region Health Outreach Program under the Medical Benefits Class Action Settlement.

As part of its monitoring of payments made by the court-supervised claims processes operated by the Deepwater Horizon Court Supervised Settlement Program (DHCSSP) for the Economic and Property Damages Settlement, BP identified multiple business economic loss claim determinations that appeared to result from an interpretation of the Economic and Property Damages Settlement Agreement by that settlement's claims administrator that BP believes was incorrect. This interpretation produced a higher number and value of awards than the interpretation BP assumed in making the initial estimate. Pursuant to the mechanisms in the Economic and Property Damages Settlement Agreement, the claims administrator sought clarification from the court on this matter and on 30 January 2013, the court initially upheld the claims administrator's interpretation of the agreement. On 6 February 2013, the court reconsidered and vacated its ruling of 30 January 2013 and stayed the processing of certain types of business economic loss claims. The court lifted the stay on 28 February 2013. Other business economic loss claims have continued to be paid at a higher average amount than previously assumed by BP in determining its initial estimate of the total cost. On 5 March 2013, the court affirmed the claims administrator's interpretation of the agreement and rejected BP's position as it relates to business economic loss claims. BP strongly disagrees with the ruling of 5 March 2013 and the current implementation of the agreement by the claims administrator. BP intends to pursue all available legal options, including rights of appeal, to challenge this ruling.

BP initially estimated the cost of the Settlements, including claims administration costs, to be approximately $7.8 billion (including the $2.3-billion commitment to help resolve economic loss claims related to the Gulf seafood industry). During the third quarter 2012, BP increased its estimate of the cost of claims administration by $280 million, and during the fourth quarter by a further $400 million as described in Financial statements – Note 36 on pages 236-239 herein. Subsequently, management has continued to analyse the business economic loss claims in the period since 5 February 2013 to gain a better understanding of whether or not the number and average value of claims received and processed to date are predictive of future claims (and so would allow management to estimate the total cost of the Settlements reliably). Management has concluded based upon this analysis that it is not possible to determine whether this claims experience to date is, or is not, an appropriate basis for determining the total cost. Therefore, given the inherent uncertainty that exists as BP pursues all available legal options to challenge the recent ruling and the higher number of claims received and higher average claims payments than previously assumed by BP which may or may not continue, management has concluded that no reliable estimate can be made of any business economic loss claims not yet received or processed by the DHCSSP.

BP's current estimate of the total cost of those elements of the Settlements that can be estimated reliably, which excludes any future business economic loss claims not yet received or processed by the DHCSSP, is $7.7 billion. If BP is successful in its challenge to the court's ruling, the total estimated cost of the Settlements will, nevertheless, be significantly higher than the current estimate of $7.7 billion, because business economic loss claims not yet received or processed are not reflected in the current estimate and the average payments per claim determined so far are higher than anticipated. If BP is not successful in its challenge to the court's ruling, a further significant increase to the total estimated cost of the Settlements will be required. However, there can be no certainty as to how the dispute will ultimately be resolved or determined. To the extent that there are insufficient funds available in the Trust fund, payments under the PSC settlement will be made by BP directly and charged to the income statement.

Significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable through the claims process. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported. In addition, there is further uncertainty in relation to interpretations of the claims administrator regarding the protocols under the Economic and Property Damages Settlement and judicial interpretation of these protocols, and the outcomes of any further litigation including in relation to potential opt-outs from the settlement or otherwise. While BP has determined its current best estimate of the cost of those aspects of the Settlements that can be measured reliably, it is possible that the actual cost could be significantly higher than this estimate due to the uncertainties noted above. In addition, a provision will be re-established for remaining business economic loss claims and the estimate will increase as more information becomes available, the interpretation of the protocols is clarified and the claims process matures, enabling BP to estimate reliably the cost of these claims. For more information, see Financial statements – Note 36 on pages 236-239 of this report.

All class member settlements under these agreements are payable under the terms of the Trust. Other costs to be paid from the Trust include State and Local government claims, state and local response costs, natural resource damages and related claims, and final judgments and settlements. The Trust may not be sufficient to satisfy all of these claims including those under the settlement agreements. Should the Trust not be sufficient, payments under the settlement agreements would be made by BP directly.

The Economic and Property Damages Settlement provides for a transition from the Gulf Coast Claims Facility (GCCF) to a new court-supervised claims programme, to administer payments made to qualifying class members. A court-supervised transitional claims process was in operation while the infrastructure for the new settlement claims process was put in place. During this transitional period (now concluded), the processing of claims that have been submitted to the GCCF continued, and new claimants submitted their claims. BP agreed not to wait for final approval of the Economic and Property Damages Settlement to pay claims. The economic and property damages claims process is under court supervision through the settlement claims process established by the Economic and Property Damages Settlement.

Under the Economic and Property Damages Settlement, class members release and dismiss their claims against BP not expressly reserved by that agreement. The Economic and Property Damages Settlement also provides that, to the extent permitted by law, BP assigns to the PSC certain of its claims, rights and recoveries against Transocean and Halliburton for damages with protections such that Transocean and Halliburton cannot pass those damages through to BP. Under the Medical Benefits Class Action Settlement, class members release and dismiss their claims against BP covered by that settlement, except that class members do not release claims for Later-Manifested Physical Conditions.

On 2 May 2012, the court overseeing the federal multi-district litigation proceedings pending in New Orleans (MDL 2179) issued orders preliminarily and conditionally certifying the Economic and Property Damages Settlement Class and the Medical Benefits Settlement Class and preliminarily approving the proposed Economic and Property Damages Settlement and the proposed Medical Benefits Class Action Settlement. Under US federal law, there is an established procedure for determining the fairness, reasonableness and adequacy of class action settlements. Pursuant to this procedure, an extensive notice programme to the public was implemented to explain the settlement agreements and class members' rights, including the right to "opt out" of the classes, and the processes for making claims. The court set a deadline of 31 August 2012 (later extended to 7 September 2012) for class members objecting to the Economic and Property Damages Settlement and/or the Medical Benefits Class Action Settlement to file their objections with the court and a deadline of 1 October 2012 (later extended to 1 November 2012) for class members to opt out of the Economic and Property Damages Class and/or the Medical Benefits Settlement Class. The Deepwater Horizon Court Supervised Settlement Program (DHCSSP), the new claims facility operating under the frameworks established by the Economic and

Property Damages Settlement, commenced operation on 4 June 2012 under the oversight of Claims Administrator Patrick Juneau. The court conducted a fairness hearing on 8 November 2012 in which to consider, among other things, whether to grant final approval of the Economic and Property Damages Settlement and the Medical Benefits Class Action Settlement, whether to certify the classes for settlement purposes only, and the merits of any objections to the settlement agreements. At the fairness hearing, the parties and objecting class members presented arguments for and against the approval of each settlement agreement and the certification of each settlement class. On 21 November 2012, the parties to the settlement filed a list of 13,123 individuals and entities who had submitted timely requests to opt out of the Economic and Property Damages Settlement Class and 1,638 individuals who had submitted timely requests to opt out of the Medical Benefits Settlement Class. On 16 November 2012, the court extended the deadline from 5 November 2012 to 15 December 2012 for such excluded persons or entities to request revocation of their requests to opt out of the settlement. As a result of such revocations, the number of opt-outs for the Economic and Property Damages Settlement and the Medical Benefits Class Action Settlement is fewer than those reported figures.

Following the fairness hearing, both settlements were approved by the district court. The Economic and Property Damages Settlement was approved on 21 December 2012 in a final order and judgment, and the Medical Benefits Class Action Settlement was approved by the district court in a final order and judgment on 11 January 2013. Since 17 January 2013, eight groups of purported members of the Economic and Property Damages Settlement Class have filed notices of appeal to the US Court of Appeals for the Fifth Circuit of the final order and judgment approving the Economic and Property Damages Settlement. Two groups of purported members of the Medical Benefits Settlement Class have also appealed from the final order and judgment approving the Medical Benefits Class Action Settlement. Additionally, a coalition of fishing and community groups has appealed from an order of the district court denying it permission to intervene in the civil action serving as the vehicle for the Economic and Property Damages Settlement and further denying it permission to take discovery regarding the fairness of that settlement.

On 18 January 2013, a purported class action was filed in federal district court in New Orleans seeking relief for all persons alleging losses caused by the Incident who are excluded from or have opted out of the Economic and Property Damages Settlement. On 8 February 2013, the action was consolidated with MDL 2179.

On 11 July 2012, BP filed motions to dismiss several categories of claims in MDL 2179 that were not covered by the Economic and Property Damages Settlement. On 1 October 2012, the court granted BP's motion, dismissing (1) claims alleging a reduction in the value of real property caused by the oil spill or other contaminant where the property was not physically touched by the oil and the property was not sold; (2) claims by or on behalf of entities marketing BP-branded fuels that they have suffered damages, including loss of business, income, and profits, as a result of the loss of value to the 'BP' brand or name; and (3) claims by or on behalf of recreational fishermen, recreational divers, beachgoers, recreational boaters, and similar claimants, that they have suffered damages that include loss of enjoyment of life from the inability to use of the Gulf of Mexico for recreation and amusement purposes. The judge did not, however, lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply his dismissal of those categories of claims to those individual complaints. This order was appealed to the US Court of Appeals for the Fifth Circuit, but the appeal was dismissed for want of prosecution on 28 January 2013. On 19 February 2013, the appeals court granted appellants' motion to reinstate the appeal, and BP moved to dismiss the appeal for lack of jurisdiction.

On 15 September 2010, three Mexican states bordering the Gulf of Mexico (Veracruz, Quintana Roo, and Tamaulipas) filed lawsuits in federal court in Texas against several BP entities. These lawsuits allege that the Incident harmed their tourism, fishing, and commercial shipping industries (resulting in, among other things, diminished tax revenue), damaged natural resources and the environment, and caused the states to incur expenses in preparing a response to the Incident. On 9 December 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted in part BP's motion to dismiss the three Mexican states' complaints, dismissing their claims under OPA 90 and for nuisance and negligence per se, and preserving their claims for negligence and gross negligence only to the extent there has been a physical injury to a proprietary interest of the states. The court in MDL 2179 has also set a schedule for targeted discovery and motions on the legal issue of whether the Mexican States of Quintana Roo, Tamaulipas, and Veracruz have a justiciable claim. BP, other defendants, and the three Mexican States filed cross-motions for summary judgment on 4 January 2013 on the issue of whether the Mexican States have a proprietary interest in the matters asserted in their complaints, and the motions remain pending. On 5 April 2011, the State of Yucatan submitted a claim to the GCCF alleging potential damage to its natural resources and environment, and seeking to recover the cost of assessing the alleged damage. BP anticipates further claims from the Mexican federal government.

On 18 October 2012, before a Federal District Court located in Mexico City, a class action complaint was filed against BPXP, BP America Production Company, and other companies affiliated with BP. The plaintiffs, consisting of fishermen and other groups, are seeking, among other things, compensatory damages for the class members who allegedly suffered economic losses, as well as an order requiring BP to remediate environmental damage resulting from the Incident and to provide funding for the preservation of the environment and to conduct environmental impact studies in the Gulf of Mexico for the next 10 years. Plaintiffs have not yet properly served the BP entities named as Defendants.

Citizens groups have also filed either lawsuits or notices of intent to file lawsuits seeking civil penalties and injunctive relief under the Clean Water Act and other environmental statutes. On 16 June 2011, the judge in the federal multi-district litigation proceeding in New Orleans granted BP's motion to dismiss a master complaint raising claims for injunctive relief under various federal environmental statutes brought by various citizens groups and others. The judge did not, however, lift an earlier stay on the underlying individual complaints raising those claims for injunctive relief or otherwise apply his dismissal of the master complaint to those individual complaints. In addition, a different set of environmental groups filed a motion to reconsider dismissal of their Endangered Species Act claims on 14 July 2011. That motion remains pending. On 31 January 2012, the court, on motion by the Center for Biological Diversity, entered final judgment on the basis of the 16 June 2011 order with respect to two actions brought against BP by that plaintiff. On 2 February 2012, the Center for Biological Diversity filed a notice of appeal of both actions. Following oral argument, the Court of Appeals ruled in BP's favour on 9 January 2013 in virtually all respects, though it remanded the Center for Biological Diversity's claim under the Emergency Planning and Community Right to Know Act to the district court. On 22 January 2013, the Center for Biological Diversity filed a Petition for Panel Rehearing in the Court of Appeals, which was denied on 4 February 2013.

On 1 March 2012, the court in MDL 2179 issued a partial final judgment dismissing with prejudice all claims by BP, Anadarko and MOEX for additional insured coverage under insurance policies issued to Transocean for the sub-surface pollution liabilities BP, Anadarko and MOEX have incurred and will incur with respect to the Macondo well oil release. BP filed a notice of appeal from the court's judgment to the US Court of Appeals for the Fifth Circuit and oral argument was conducted on 3 December 2012. On 1 March 2013, the appeals court reversed the district court's judgment, rejecting the district court's ruling that the insurance that BP is entitled to receive as an additional insured under the Transocean insurance policies at issue is limited to the scope of the indemnity in the drilling contract between BP and Transocean.

In addition, BP is aware that actions have been or may be brought under the Qui Tam (whistle-blower) provisions of the False Claims Act (FCA). On 17 December 2012, the court ordered unsealed one complaint that had been filed in the US District Court for the Eastern District of Louisiana by one individual under the FCA's Qui Tam provisions. The complaint alleged that BP and another defendant had made false reports and certifications of the amount of oil released into the Gulf of Mexico following the Incident. On 17 December 2012, the DoJ filed with the court a notice that the DoJ elected to decline to intervene in the action.

On 21 April 2011, BP announced an agreement with natural resource trustees for the US and five Gulf Coast states, providing for up to $1 billion to be spent on early restoration projects to address natural resource injuries resulting from the Incident. Funding for these projects will come from the $20-billion Trust fund.

A claim was commenced against BP by a group of claimants on 26 July 2012 in Ecuador. The majority of the claimants represent local NGOs. The claim alleges that through the Incident and BP's response to it, BP violated the "rights of nature". The claim is not monetary but rather seeks injunctive relief. Two previous claims on identical grounds were previously dismissed at an early stage by the Ecuadorian courts. On 3 December 2012, the Ecuadorian court of first instance dismissed the claim. On 7 December 2012, the claimants filed a timely notice of appeal to the Ecuadorian court of second instance. On 28 February 2013, the court affirmed the dismissal by the lower court.

BP's potential liabilities resulting from threatened, pending and potential future claims, lawsuits and enforcement actions relating to the Incident, together with the potential cost of implementing remedies sought in the various proceedings, cannot be fully estimated at this time but they have had and are expected to have a material adverse impact on the group's business, competitive position, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda, particularly in the US. These potential liabilities may continue to have a material adverse effect on the group's results and financial condition. See Financial statements – Note 2 on page 194 for information regarding the financial impact of the Incident.

Pending investigations and reports relating to the Deepwater Horizon oil spill

The US Chemical Safety and Hazard Investigation Board (CSB) is conducting an investigation of the Incident that is focused on the explosions and fire, and not the resulting oil spill or response efforts. As part of this effort, on 24 July 2012, the CSB conducted a hearing at which it released its preliminary findings on, among other things, the use of safety indicators by industry (including BP and Transocean) and government regulators in offshore operations prior to the accident. The CSB found that BP and other offshore industry members have placed too great an emphasis on personal safety rather than process safety overall. The CSB has indicated that it plans to issue its final report in April 2013. The CSB will seek to recommend improvements to BP and industry practices and to regulatory programmes to prevent recurrence and mitigate potential consequences.

A Committee of the National Academy of Engineering/National Research Council is looking at the methodologies available for assessing spill impacts on ecosystem services in the Gulf of Mexico, with a final report expected in the first or second quarter of 2013.

Other legal proceedings

The US Federal Energy Regulatory Commission (FERC) and the US Commodity Futures Trading Commission (CFTC) are currently investigating several BP entities regarding trading in the next-day natural gas market at Houston Ship Channel during September, October and November 2008. The FERC Office of Enforcement staff notified BP on 12 November 2010 of their preliminary conclusions relating to alleged market manipulation in violation of 18 C.F.R. Sec. 1c.1. On 30 November 2010, CFTC Enforcement staff also provided BP with a notice of intent to recommend charges based on the same conduct alleging that BP engaged in attempted market manipulation in violation of Section 6(c), 6(d), and 9(a)(2) of the Commodity Exchange Act. On 23 December 2010, BP submitted responses to the FERC and CFTC November 2010 notices providing a detailed response that it did not engage in any inappropriate or unlawful activity. On 28 July 2011, the FERC staff issued a Notice of Alleged Violations stating that it had preliminarily determined that several BP entities fraudulently traded physical natural gas in the Houston Ship Channel and Katy markets and trading points to increase the value of their financial swing spread positions. Other investigations into BP's trading activities continue to be conducted from time to time.

On 23 March 2005, an explosion and fire occurred at the Texas City refinery. Fifteen workers died in the incident and many others were injured. BP Products has resolved all civil injury claims and all civil and criminal governmental claims arising from the March 2005 incident.

In March 2007, the US Chemical Safety and Hazard Investigation Board (CSB) issued a report on the incident. The report contained recommendations to the Texas City refinery and to the board of directors of BP. To date, CSB has accepted as satisfactorily addressed the majority of BP's responses to its recommendations. BP and the CSB are continuing to discuss the remaining open recommendations with the objective of the CSB agreeing to accept these as satisfactorily addressed as well.

On 29 October 2009, the US Occupational Safety and Health Administration (OSHA) issued citations to the Texas City refinery related to the Process Safety Management (PSM) Standard. On 12 July 2012, OSHA and BP resolved 409 of the 439 citations. The agreement required that BP pay a civil penalty of $13,027,000 and that BP abate the alleged violations by 31 December 2012. BP completed these requirements and the agreement has terminated. The settlement excluded 30 citations for which BP and OSHA could not reach agreement. However, the parties agreed that BP's penalty liability will not exceed $1 million if those citations are resolved through litigation. Additional efforts will be made in the future to resolve these citations.

On 8 March 2010, OSHA issued 65 citations to BP Products and BP-Husky for alleged violations of the PSM Standard at the Toledo refinery, with penalties of approximately $3 million. These citations resulted from an inspection conducted pursuant to OSHA's Petroleum Refinery Process Safety Management National Emphasis Program. Both BP Products and BP-Husky contested the citations, and a trial of 42 citations was completed in June 2012 before an Administrative Law Judge from the OSH Review Commission. A decision is expected in mid-2013.

A flaring event occurred at the Texas City refinery in April and May 2010. This flaring event is the subject of civil lawsuit claims for personal injury and, in some cases, property damage by roughly 50,000 individuals. These lawsuit claims have been consolidated in a Texas multi-district litigation proceeding in Galveston, Texas. A trial of six selected plaintiffs is scheduled for trial in September 2013. Also, this flaring event, and other refinery emissions from December 2008 through 2010, is the subject of a purported class action, on behalf of some local residential property owners, filed in US federal district court in Galveston. The purported class plaintiffs claim that refinery emissions caused their residential properties to lose value. No class has been certified, and no trial date has been set. In addition, the flares involved in this event are the subject of a federal government enforcement action.

In March and August 2006, oil leaked from oil transit pipelines operated by BP Exploration (Alaska) Inc. (BPXA) at the Prudhoe Bay unit on the North Slope of Alaska. On 12 May 2008, a BP p.l.c. shareholder filed a consolidated complaint alleging violations of federal securities law on behalf of a putative class of BP p.l.c. shareholders against BP p.l.c., BPXA, BP America, and four officers of the companies, based on alleged misrepresentations concerning the integrity of the Prudhoe Bay pipeline before its shutdown on 6 August 2006. On 8 February 2010, the Ninth Circuit Court of Appeals accepted BP's appeal from a decision of the lower court granting in part and denying in part BP's motion to dismiss the lawsuit. On 29 June 2011, the Ninth Circuit ruled in BP's favour that the filing of a trust related agreement with the SEC containing contractual obligations on the part of BP was not a misrepresentation which violated federal securities laws. The BP p.l.c. shareholder filed an amended complaint, in response to which BP filed a new motion to dismiss, which was granted on 14 March 2012. The plaintiff has appealed the court's dismissal of the case, and the appeal is pending. On 31 March 2009, the State of Alaska filed a complaint 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. In December 2011, the State of Alaska and BPXA entered into a Dispute Resolution Agreement concerning this matter that resulted in arbitration of the amount of the State's lost royalty income and payment by BPXA of the additional amount of $10 million on account of other claims in the complaint. Evidentiary hearings in the arbitration occurred in May and June 2012, and an award was issued by the arbitration panel in November 2012 in the approximate amount of $245 million. BPXA's working interest share of that award is approximately $66 million. All amounts due to the State of Alaska in this matter were paid in November 2012.

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 Company (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 judgment 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. It intends to defend such actions vigorously and believes that the incurrence of liability is remote. Consequently, BP believes that the impact of these lawsuits on the group's results, financial position or liquidity will not be material.

In April 2009, Kenneth Abbott, as relator, filed a US False Claims Act lawsuit against BP, alleging that BP violated federal regulations, and made false statements in connection with its compliance with those regulations, by failing to have necessary documentation for the Atlantis subsea and other systems. BP is the operator and 56% interest owner of the Atlantis unit in production in the Gulf of Mexico. That complaint was unsealed in May 2010 and served on BP in June 2010. Abbott seeks damages measured by the value, net of royalties, of all past and future production from the Atlantis platform, trebled, plus penalties. In September 2010, Kenneth Abbott and Food & Water Watch filed an amended complaint in the False Claims Act lawsuit seeking an injunction shutting down the Atlantis platform. The court denied BP's motion to dismiss the complaint in March 2011. Separately, also in March 2011, BOEMRE issued its investigation report of the Abbott Atlantis allegations, which concluded that Kenneth Abbott's allegations that Atlantis operations personnel lacked access to critical, engineer-approved drawings were without merit and that his allegations about false submissions by BP to BOEMRE were unfounded. Trial was scheduled to begin on 10 April 2012, but the trial date was vacated and not rescheduled pending consideration of the parties' summary judgment motions.

Various non-governmental organizations ("NGOs") and the EPA challenged certain aspects of the air permits issued by the Indiana Department of Environmental Management (IDEM) related to the Whiting refinery modernization project. BP has been in discussions with the EPA, the IDEM and certain environmental groups over these and other Clean Air Act (CAA) issues relating to the Whiting refinery. BP has also been in discussions with the EPA regarding alleged CAA violations at the Toledo, Carson and Cherry Point refineries.

On 23 May 2012, BP Products North America, Inc., the EPA, the Department of Justice (DoJ), the IDEM and the NGOs resolved objections to the air permit for the Whiting refinery modernization project and settled allegations of air emissions violations at the Whiting refinery. The settlement requires emission reduction projects with an estimated cost of approximately $400 million and the payment of a civil penalty of $8 million. The settlement was approved by the federal court on 6 November 2012. On 20 December 2012 IDEM issued the final, revised air permit for the modernization project that incorporates the relevant consent decree provisions.

An application was brought in the English High Court on 1 February 2011 by Alfa Petroleum Holdings Limited and OGIP Ventures Limited against BP International Limited and BP Russian Investments Limited alleging breach of a Shareholders Agreement on the part of BP and seeking an interim injunction restraining BP from taking steps to conclude, implement or perform the transactions with Rosneft Oil Company, originally announced on 14 January 2011, relating to oil and gas exploration, production, refining and marketing in Russia (the Arctic Opportunity). Those transactions included the issue or transfer of shares between Rosneft Oil Company and any BP group company (pursuant to the Rosneft Share Swap Agreement). The court granted an interim order restraining BP from taking any further steps in relation to the Arctic Opportunity pending an expedited UNCITRAL arbitration procedure in accordance with the Shareholders Agreement between the parties. The arbitration commenced and the interim injunction was continued by the arbitration panel. On 17 May 2011, BP announced that both the Rosneft Share Swap Agreement and the Arctic Opportunity, originally announced on 14 January 2011, had terminated. This termination was as a result of the deadline for the satisfaction of conditions precedent having expired following delays resulting from the interim orders referred to above. These interim orders did not address the question of whether or not BP breached the Shareholders Agreement. The arbitration proceedings, which addressed the allegation of breach by BP for late notification to TNK-BP shareholders Alfa, Access and Renova (AAR) of the Arctic Opportunity, was settled on 13 November 2012 as part of a settlement of all the outstanding disputes between BP and AAR.

Five minority shareholders of OAO TNK-BP Holding (TBH) filed two civil actions in Tyumen, Siberia, against BP Russian Investments Limited (BPRIL) and BP p.l.c. and against two of the BP nominated directors of TBH. These two actions sought to recover alleged losses to TBH of $13 billion and $2.7 billion respectively arising from the failure to involve TNK-BP in BP's proposed alliance with Rosneft. On 11 November 2011, the Tyumen Court dismissed both claims fully on their merits. The plaintiffs appealed both of these decisions to the Omsk Appellate court. On 26 January 2012, the Appellate court upheld the Tyumen Court's dismissal of the claim in relation to the BP nominated directors of TBH. The Omsk Appellate court subsequently upheld the Tyumen court of first instance's dismissal of the minority suits against BPRIL and BP p.l.c. The plaintiffs then appealed both of the Omsk Appellate court decisions to the cassation court of appeal in Tyumen. The cassation court upheld the dismissal of the claim against the BP nominated directors, and the case against the BP nominated directors is now resolved. However, the cassation court remitted the case against the BP companies back to the Tyumen Court of first instance for reconsideration. The plaintiffs amended their claim to reduce their damages to approximately $8.6 billion. On 27 July 2012 the Tyumen Court ruled in favour of the plaintiffs and awarded $3.0 billion in damages against the BP companies. BPRIL filed an appeal of the Tyumen Court's decision with the Omsk Appellate court. In addition, Rosneft and BP-nominated directors of TNK-BP Ltd. filed statements in support of the contention that the award is unjustified, and the plaintiffs' claims wholly without merit. On 25 October 2012 the Omsk Appellate court adjourned its hearing of the appeal until 9 November 2012 and subsequently until 14 December 2012. At that hearing the minority shareholder petitioned the court to withdraw the lawsuit. The court adjourned that hearing until 24 January 2013 upon the motion of Rosneft. At the hearing on 24 January 2013 the court acceded to the motion of the minority shareholder to withdraw the claim and ruled that the claim should be withdrawn. Rosneft has appealed this ruling to the Tyumen Court of Cassation on the basis that the claim should be dismissed on the merits as an abuse of process rather than be simply withdrawn. The hearing of Rosneft's appeal is scheduled to take place on 23 April 2013.

On 24 January 2012, the Republic of Bolivia issued a press statement declaring its intent to nationalize Pan American Energy's interests in the Caipipendi Operations Contract. Nevertheless, no formal decision has been issued or announced by the government, and no nationalization process has commenced. Pan American Energy and its shareholders BP and Bridas intend to vigorously defend their legal interests under the Caipipendi Operations Contract and available Bilateral Investment Treaties.

Critical accounting policies

The significant accounting policies of the group are summarized in Financial statements – Note 1 on page 186.

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for BP management to make judgements, 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 period. Actual outcomes could differ from the estimates and assumptions used. The following summary provides more information about the critical accounting judgements and estimates that could have a significant impact on the results of the group and should be read in conjunction with the information provided in the Notes on financial statements, including Note 1 Significant accounting policies.

The areas requiring the most significant judgement and estimation 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, business combinations, taxation, derivative financial instruments, provisions and contingencies, and in particular, provisions and contingencies related to the Gulf of Mexico oil spill, 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, appraisal and development expenditure. The group's accounting policy for oil and natural gas exploration, appraisal and development expenditure is provided in Financial statements – Note 1 on page 186.

The accounting for oil and natural gas exploration, appraisal and development expenditure requires the use of various judgements and estimates in management's determination of the economic viability of a project based on a range of technical and commercial considerations, the establishment of development plans and timing, and estimates of future expenditure.

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 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.

The determination of the group's estimated oil and gas reserves requires significant judgements and estimates to be applied and these are regularly reviewed and updated. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity, drilling of new wells and commodity prices all impact on the determination of the group's estimates of its oil and gas reserves. BP bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice.

The estimation of oil and natural gas reserves and BP's process to manage reserves bookings is described in Exploration and Production – Oil and gas disclosures on page 263, which is unaudited. Details on BP's proved reserves and production compliance and governance processes are provided on pages 84-89.

Estimates of oil and gas reserves are used to calculate depreciation, depletion and amortization charges for the group's oil and gas properties. 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. As discussed below, oil and natural gas reserves also have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements.

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 below).

The 2012 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 page 263. Information on the carrying amounts of the group's oil and gas properties, together with the amounts recognized in the income statement as depreciation, depletion and amortization is contained in Financial statements – Note 15 and Note 9 respectively.

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, with corresponding reductions in the carrying values of the group's assets. Such indicators include changes in the group's business plans, changes in commodity prices leading to sustained unprofitable performance, low plant utilization, evidence of physical damage, 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. 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 using management's best estimate of future oil and natural gas prices and reserves volumes. 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 price assumptions thereafter. As at 31 December 2012, the group's long-term price assumptions were $90 per barrel for Brent and $6.50/mmBtu for Henry Hub (2011 $90 per barrel and $6.50/mmBtu). These long-term price assumptions are subject to periodic review and modification. The estimated future level of production is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes 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 2012 the rates ranged from 12% to 14% nominal (2011 12% to 14% nominal). The discount rates applied in assessments of impairment are reassessed each year.

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 $11.9 billion on its balance sheet (2011 $12.1 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. In testing goodwill for impairment, the group uses a similar approach to that described above for asset impairment. 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.

Refer to Oil and natural gas accounting above for a discussion on the recoverability of intangible exploration and appraisal expenditure.

Details of impairment charges recognized in the income statement are provided in Financial statements – Note 5 and details on the carrying amounts of assets are shown in Financial statements – Note 21, Note 22 and Note 23.

Judgements are also required in assessing the recoverability of overdue trade receivables and determining whether a provision against the future recoverability of those receivables is required. Factors considered include the credit rating of the counterparty, the amount and timing of anticipated future payments and any possible actions that can be taken to mitigate the risk of non-payment.

Business combinations

Accounting for business combinations using the acquisition method requires the determination of the fair value of the consideration transferred, together with the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date. Goodwill is measured as being the excess of the aggregate of the consideration transferred, the amount recognized for any minority interest and the acquisition-date fair values of any previously held interest in the acquiree over the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date.

Judgement is required in determining whether a transaction meets the criteria to be treated as a business combination or not. Judgements and estimates are also required in order to determine the fair values of the assets acquired and the liabilities assumed, and the group uses all available information, including external valuations and appraisals where appropriate, to determine these fair values. If necessary, the group has up to one year from the acquisition date to finalize the determinations of fair value.

Details of the business combinations undertaken by the group in 2012 are provided in Financial statements – Note 3 on page 198.

Taxation

The computation of the group's income tax expense and liability 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 and tax credits 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 or tax credits 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, income tax charges or credits, and changes in deferred tax assets or liabilities, may arise in future periods. For more information see Financial statements – Note 18 on page 212 and Note 43 on page 253.

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. Forward contracts to buy or sell equity investments, including investments in associates and joint ventures, are also accounted for as derivative financial instruments. 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. Derivatives relating to unquoted equity instruments are carried at cost where it is not possible to reliably measure their fair value subsequent to initial recognition. 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 internal models and other valuation methods due to the absence of quoted prices or other observable, market-corroborated data. This applies to the group's longer-term, structured derivative products and complex options, to the forward contracts to purchase shares in Rosneft, as well as to the majority of the group's natural gas embedded derivatives. The group's embedded derivatives arise primarily from long-term UK gas contracts that use pricing formulae 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 fair value gains and losses on derivatives and embedded derivatives recognized in the income statement. For more information see Financial statements – Note 33 on page 228.

Details of the value-at-risk techniques used by the group to measure market risk exposure arising from its derivative trading positions is provided in Financial statements – Note 26 on page 220. 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 26 on page 220.

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 decommissioning obligations facing BP relate to the plugging and abandonment of wells and the removal and disposal of oil and natural gas platforms and pipelines around the world. The estimated discounted costs of performing this work are recognized as we drill the wells and install the 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 decommissioning 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. Decommissioning 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. Any 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 recognized, 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 2012 was 0.5% (2011 0.5%). The interest rate is based on the real rate (i.e. excluding the impacts of inflation) on long-dated government bonds.

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 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 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 2012 was 0.5% (2011 0.5%).

Information about the group's provisions is provided in Financial statements – Note 36.

As further described in Financial statements – Note 43 on page 253, 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 established or revised. Accordingly, significant management judgement relating to provisions and contingent liabilities is required, since the outcome of litigation is difficult to predict.

Gulf of Mexico oil spill

Detailed information on the Gulf of Mexico oil spill, including the financial impacts, is provided in Financial statements – Note 2 on page 194.

As a consequence of the Gulf of Mexico oil spill, as described on pages 59-62, BP continues to incur various costs and has also recognized liabilities for future costs. Liabilities of uncertain timing or amount and contingent liabilities have been accounted for and/or disclosed in accordance with IAS 37 'Provisions, contingent liabilities and contingent assets'. BP's rights and obligations in relation to the $20-billion trust fund which was established in 2010, and in relation to the qualifying settlement funds established pursuant to the agreement with the Plaintiffs' Steering Committee (PSC), are accounted for in accordance with IFRIC 5 'Rights to interests arising from decommissioning, restoration and environmental rehabilitation funds'.

The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors. Furthermore, significant uncertainty exists in relation to the amount of claims that will become payable by BP, the amount of fines that will ultimately be levied on BP (including any determination of BP's culpability based on any findings of negligence, gross negligence or wilful misconduct), the outcome of litigation and arbitration proceedings, and any costs arising from any longer-term environmental consequences of the oil spill, which will also impact upon the ultimate cost for BP. The amount and timing of any amounts payable could also be impacted by any further settlements which may or may not occur.

Although the provision recognized is the current best reliable estimate of expenditures required to settle certain present obligations at the end of the reporting period, there are future expenditures for which it is not possible to measure the obligation reliably as noted below under Contingent liabilities.

The total amounts that will ultimately be paid by BP in relation to all the obligations relating to the accident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors, as discussed under Contingent liabilities in Financial statements – Note 43 on page 253, including in relation to any new information or future developments. These could have a material impact on our consolidated financial position, results of operations and cash flows. The risks associated with the accident could also heighten the impact of the other risks to which the group is exposed, as further described in Risk factors on pages 38-44.

Expenditure to be met from the $20-billion trust fund

In 2010, BP established the Deepwater Horizon Oil Spill Trust (the Trust) to be funded in the amount of $20 billion over the period to the fourth quarter of 2013, which is available to satisfy legitimate individual and business claims that were previously administered by the Gulf Coast Claims Facility (GCCF), state and local government claims resolved by BP, final judgments and settlements, state and local response costs, and natural resource damages and related costs. The Trust is available to satisfy claims that were previously processed through the transitional court-supervised claims facility, to fund the qualified settlement funds established under the terms of the settlement agreements with the PSC administered through the Deepwater Horizon Court Supervised Settlement Program (DHCSSP), and the separate BP claims programme.

The funding of the Trust has now been completed, with the final contribution of $860 million having been made in the fourth quarter of 2012. The income statement charge for 2010 included $20 billion in relation to the trust fund, adjusted to take account of the time value of money. Fines and penalties are not covered by the trust fund.

An asset has been recognized representing BP's right to receive reimbursement from the trust fund. This is the portion of the estimated future expenditure provided for that will be settled by payments from the trust fund. We use the term 'reimbursement asset' to describe this asset. BP will not actually receive any reimbursements from the trust fund, instead payments will be made directly to claimants from the trust fund, and BP will be released from its corresponding obligation.

The $20-billion trust fund may not be sufficient to satisfy all claims under the Oil Pollution Act 1990 (OPA 90) or otherwise that will ultimately be paid.

Contingent liabilities relating to the Gulf of Mexico oil spill

It is not possible, at this time, to measure reliably other obligations arising from the accident, namely any obligation in relation to Natural Resource Damages claims (except for the estimated costs of the assessment phase and the costs relating to early restoration agreements), the cost of business economic loss claims under the PSC settlement not yet received or processed by the DHCSSP, or any other potential litigation (including through excluded parties from the PSC settlement and any obligation in relation to other potential private or governmental litigation), fines or penalties (except for the Clean Water Act civil penalty claims and governmental claims), nor is it practicable to estimate their magnitude or possible timing of payment. Therefore no amounts have been provided for these obligations as at 31 December 2012.

Under the settlement agreements with co-owners Anadarko and MOEX, and with Cameron International, the designer and manufacturer of the Deepwater Horizon blowout preventer, with M-I L.L.C, (M-I), the mud contractor, and with Weatherford, the designer and manufacturer of the float collar used on the Macondo well, BP has agreed to indemnify Anadarko, MOEX, Cameron, M-I and Weatherford for certain claims arising from the accident. It is therefore possible that BP may face claims under these indemnities, but it is not currently possible at this time to reliably measure any obligation in relation to such claims and therefore no amount has been provided as at 31 December 2012.

Business economic loss claims received by the DHCSSP to date are being paid at a significantly higher average amount than previously assumed by BP in formulating the original estimate of the cost of the PSC settlement. Further, the settlement agreement has been interpreted by the claims administrator in a way that BP believes is incorrect resulting in a higher number and amount of claims being determined. As more fully described in Legal proceedings on pages 162-169, this matter has been considered by the court and on 5 March 2013, the court affirmed the claims administrator's interpretation of the settlement agreement and rejected BP's position as it relates to business economic loss claims. BP strongly disagrees with the ruling of 5 March 2013, and intends to pursue all available legal options, including rights of appeal, to challenge this ruling. Given the inherent uncertainty that exists as BP pursues all available legal options to challenge the recent ruling, and the higher number of claims received and higher average claims payments than previously assumed by BP, which may or not continue, management has concluded that no reliable estimate can be made of any business economic loss claims not yet received or processed by the DHCSSP.

BP's current estimate of the total cost of those elements of the PSC settlement that can be estimated reliably, which excludes any future business economic loss claims not yet received or processed by the DHCSSP, is $7.7 billion. If BP is successful in its challenge to the court's ruling, the total estimated cost of the settlement agreement will, nevertheless, be significantly higher than the current estimate of $7.7 billion, because business economic loss claims not yet received or processed are not reflected in the current estimate and the average payments per claim determined so far are higher than anticipated. If BP is not successful in its challenge to the court's ruling, a further significant increase to the total estimated cost of the settlement will be required. However, there can be no certainty as to how the dispute will ultimately be resolved or determined. To the extent that there are insufficient funds available in the Trust fund, payments under the PSC settlement will be made by BP directly and charged to the income statement. For further information see Financial statements – Note 36 and Note 43 and Risk factors on pages 38-44.

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, assumptions for inflation rates, US healthcare cost trend rates and rates of utilization of healthcare services by US 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. In 2013, when we adopt the revised version of IAS 19 'Employee benefits' (see Note 1 for further information), we will be required to apply the same rate of return on plan assets as we use to discount our pension liabilities. We expect this accounting change to adversely impact our earnings by approximately $1 billion on a pre-tax basis, with no impact on cash flow.

The pension and other post-retirement benefit assumptions at December 2012, 2011 and 2010 are provided in Financial statements – Note 37 on page 239.

The assumed rate of investment return, discount rate, inflation 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 37 on page 239.

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 37 on page 239.

Actuarial gains and losses are recognized in full within other comprehensive income in the year in which they occur.

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 is 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.

Material contracts

On 6 August 2010, BP entered into a trust agreement with John S Martin, Jr and Kent D Syverud, as individual trustees, and Citigroup Trust-Delaware, N.A., as corporate trustee (the Trust Agreement) which established the Deepwater Horizon Oil Spill Trust (the Trust) to be funded in the amount of $20 billion (the trust fund) over the period to the fourth quarter of 2013. During the fourth quarter of 2012, BP made a final contribution to the Trust to complete the funding of the full $20-billion commitment. The trust fund is available to satisfy legitimate individual and business claims that were previously administered by the Gulf Coast Claims Facility (GCCF), state and local government claims resolved by BP, final judgments and settlements, state and local response costs, and natural resource damages and related costs. The trust fund is available to satisfy claims that were previously processed through the transitional court-supervised claims facility, to fund the qualified settlement funds established under the terms of the settlement agreements with the Plaintiffs' Steering Committee (PSC) administered through the court-supervised settlement program, and to satisfy claims processed through the separate BP claims program in respect of claimants not in the Economic and Property Damages class as determined by the Economic and Property Damages Settlement Agreement or who have requested to opt out of that settlement. Fines, penalties and claims administration costs are not covered by the trust fund. Under the terms of the Trust Agreement, BP has no right to access the funds once they have been contributed to the trust fund. BP will receive funds from the trust fund only upon its expiration, if there are any funds remaining at that point. BP has the authority under the Trust Agreement to present certain resolved claims, including natural resource damages claims and state and local response claims, to the Trust for payment, by providing the trustees with all the required documents establishing that such claims are valid under the Trust Agreement. However, any such payments can only be made on the authority of the trustee and any funds distributed are paid directly to the claimants, not to BP. The Trust Agreement is governed by the laws of the State of Delaware.

On 30 September 2010, BP entered a pledge and collateral agreement in favour of John S Martin, Jr and Kent D Syverud (the Pledge Agreement), which pledged certain Gulf of Mexico assets as collateral for the trust fund funding obligation. The pledged collateral consists of an overriding royalty interest in oil and gas production of BP's Thunder Horse, Atlantis, Mad Dog, Great White and Mars, Ursa and Na Kika assets in the Gulf of Mexico. A wholly owned company called Verano Collateral Holdings LLC (Verano) has been created to hold the overriding royalty interest, which was capped at $1.25 billion per quarter and $17 billion in total. Verano pledged the overriding royalty interest to the Trust as collateral for BP's remaining contribution obligations to the Trust. An event of default under the Pledge Agreement arose if BP failed to make any contribution under the Trust Agreement when due or otherwise failed to observe certain other obligations, subject to specified cure periods. Following an event of default, the trustees were entitled to exercise all remedies as secured parties in respect of the collateral, including receipt of royalty interests from the pledged assets, having all or part of the limited liability company interests registered in the trustees' name and selling the collateral at public or private sale. The Pledge Agreement was governed by the laws of the State of Texas. On 9 November 2011 the Pledge Agreement and the related overriding royalty interest conveyance and mortgage were amended and restated (such documents collectively referred to as the Amended and Restated Pledge Agreement) to change the overriding royalty interest effective as of 1 October 2011 to $14.7 billion. Beginning on 2 January 2012, and on the first business day of each subsequent calendar quarter, the overriding royalty interest is recalculated as the remaining outstanding contributions owed by BP to the Trust as of that date multiplied by a factor of 1.45. On 2 January 2012 the overriding royalty interest was recalculated as $7.1 billion. The Amended and Restated Pledge Agreement also changed the definition of an event of default to be a failure by BP to make required payments pursuant to the terms of the Trust Agreement. BP completed its trust funding obligation during the fourth quarter of 2012, and the Amended and Restated Pledge Agreement was terminated in accordance with its terms as of 16 November 2012.

Related-party transactions

Transactions between the group and its significant jointly controlled entities and associates are summarized in Financial statements – Note 24 on page 218 and Note 25 on page 219. 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 2012 to 19 February 2013.

Exhibits

The following documents are filed in the Securities and Exchange Commission (SEC) EDGAR system, as part of this Annual Report on Form 20-F, and can be viewed on the SEC's website.

Exhibit 1	Memorandum and Articles of Association of BP p.l.c.*†
Exhibit 4.1	The BP Executive Directors' Incentive Plan*†
Exhibit 4.2	Amended BP Deferred Annual Bonus Plan 2005†
Exhibit 4.3	Amended Director's Secondment Agreement for R W Dudley†
Exhibit 4.4	Amended Director's Service Contract and Secondment Agreement for R W Dudley*†
Exhibit 4.5	Amended Director's Service Contract and Secondment Agreement for Dr B E Grote**†
Exhibit 4.6	Director's Service Contract for I C Conn***†
Exhibit 4.7	Director's Service Contract for Dr B Gilvary**†
Exhibit 7	Computation of Ratio of Earnings to Fixed Charges (Unaudited)†
Exhibit 8	Subsidiaries (included as Note 45 to the Financial Statements)
Exhibit 10.1	Trust Agreement dated as of 6 August 2010 among BP Exploration & Production Inc., John S Martin, Jr and Kent D Syverud, as individual trustees, and Citigroup Trust-Delaware, N.A., as corporate trustee, as amended by an Addendum, dated 6 August 2010*†
Exhibit 11	Code of Ethics****†
Exhibit 12	Rule 13a – 14(a) Certifications†
Exhibit 13	Rule 13a – 14(b) Certifications#†
Exhibit 99.1	Judgment in a Criminal Case and Order as to BP Exploration and Production, Inc., in United States of America v. BP Exploration and Production, Inc., dated 29 January 2013†
Exhibit 99.2	Consent of defendant BP p.l.c., dated 3 October 2012†
Exhibit 99.3	Final Judgment and Order as to defendant BP p.l.c., in Securities and Exchange Commission v. BP p.l.c., dated 10 December 2012†

* Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2010.

** Incorporated by reference to the company's Annual Report on Form 20-F for the year ended 31 December 2011.

*** 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 2009.

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 SEC on request.

Financial statements

Statement of directors' responsibilities

The directors are responsible for preparing the Annual Report and the financial statements in accordance with applicable law and regulations.

The directors are required by the UK Companies Act 2006 to prepare financial statements for each financial year that give a true and fair view of the financial position of the group and the parent company and the financial performance and cash flows of the group and parent company for that period. Under that law they are required to prepare the consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU) and applicable law and have elected to prepare the parent company financial statements in accordance with applicable United Kingdom law and United Kingdom accounting standards (United Kingdom generally accepted accounting practice). In preparing the consolidated financial statements the directors have also elected to comply with IFRSs as issued by the International Accounting Standards Board (IASB). In preparing those financial statements, the directors are required to:

- select suitable accounting policies and then apply them consistently.
- make judgements and estimates that are reasonable and prudent.
- present information, including accounting policies, in a manner that provides relevant, reliable, comparable and understandable information.
- provide additional disclosure when compliance with the specific requirements of IFRS is insufficient to enable users to understand the impact of particular transactions, other events and conditions on the group's financial position and financial performance.
- state that applicable accounting standards have been followed, subject to any material departures disclosed and explained in the parent company financial statements.
- prepare the financial statements on the going concern basis unless it is inappropriate to presume that the company will continue in business.

The directors are responsible for keeping proper accounting records that disclose with reasonable accuracy at any time the financial position of the group and company and enable them to ensure that the consolidated financial statements comply with the Companies Act 2006 and Article 4 of the IAS Regulation and the parent company financial statements comply with the Companies Act 2006. They are also responsible for safeguarding the assets of the group and company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

The directors draw attention to Notes 2, 36 and 43 on the consolidated financial statements which describe the uncertainties surrounding the amounts and timings of liabilities arising from the Gulf of Mexico oil spill.

The group's business activities, performance, position and risks are set out in this report. The financial position of the group, its cash flows, liquidity position and borrowing facilities are detailed in the appropriate sections on pages 90-93 and elsewhere in the notes on the consolidated financial statements. The report also includes details of the group's risk mitigation and management. Information on the Gulf of Mexico oil spill and BP's response is included on pages 59-62 and elsewhere in this report, including Safety on pages 46-50. The group has considerable financial resources, and the directors believe that the group is well placed to manage its business risks successfully. After making enquiries, the directors have a reasonable expectation that the company and the group have adequate resources to continue in operational existence for the foreseeable future. Accordingly, they continue to adopt the going concern basis in preparing the annual report and accounts.

Having made the requisite enquiries, so far as the directors are aware, there is no relevant audit information (as defined by Section 418(3) of the Companies Act 2006) of which the company's auditors are unaware, and the directors have taken all the steps they ought to have taken to make themselves aware of any relevant audit information and to establish that the company's auditors are aware of that information.

The directors confirm that to the best of their knowledge:

- the consolidated financial statements, prepared in accordance with IFRS as issued by the IASB, IFRS as adopted by the EU and in accordance with the provisions of the Companies Act 2006, give a true and fair view of the assets, liabilities, financial position and profit or loss of the group;
- the parent company financial statements, prepared in accordance with United Kingdom generally accepted accounting practice, give a true and fair view of the assets, liabilities, financial position, performance and cash flows of the company; and
- the management report, which is incorporated in the directors' report, includes a fair review of the development and performance of the business and the position of the group, together with a description of the principal risks and uncertainties.

This page does not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Consolidated financial statements of the BP group

Independent auditor's report on the Annual Report and Accounts to the members of BP p.l.c.

We have audited the consolidated financial statements of BP p.l.c. for the year ended 31 December 2012 which comprise the group income statement, the group statement of comprehensive income, the group statement of changes in equity, the group balance sheet, the group cash flow statement and the related notes 1-45. The financial reporting framework that has been applied in their preparation is applicable law and International Financial Reporting Standards (IFRS) as adopted by the European Union.

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Respective responsibilities of directors and auditor

As explained more fully in the Statement of directors' responsibilities set out on page 178, the directors are responsible for the preparation of the consolidated financial statements and for being satisfied that they give a true and fair view. Our responsibility is to audit and express an opinion on the consolidated financial statements in accordance with applicable law and International Standards on Auditing (UK and Ireland). Those standards require us to comply with the Auditing Practices Board's Ethical Standards for Auditors.

Scope of the audit of the financial statements

An audit involves obtaining evidence about the amounts and disclosures in the financial statements sufficient to give reasonable assurance that the financial statements are free from material misstatement, whether caused by fraud or error. This includes an assessment of: whether the accounting policies are appropriate to the group's circumstances and have been consistently applied and adequately disclosed; the reasonableness of significant accounting estimates made by the directors; and the overall presentation of the financial statements. In addition, we read all the financial and non-financial information in the annual report to identify material inconsistencies with the audited financial statements. If we become aware of any apparent material misstatements or inconsistencies we consider the implications for our report.

Opinion on financial statements

In our opinion the consolidated financial statements:

- give a true and fair view of the state of the group's affairs as at 31 December 2012 and of its profit for the year then ended;
- have been properly prepared in accordance with IFRS as adopted by the European Union; and
- have been prepared in accordance with the requirements of the Companies Act 2006 and Article 4 of the IAS Regulation.

Separate opinion in relation to IFRS as issued by the International Accounting Standards Board

As explained in Note 1 to the consolidated financial statements, the group in addition to applying IFRS as adopted by the European Union, has also applied IFRS as issued by the International Accounting Standards Board (IASB). In our opinion the consolidated financial statements comply with IFRS as issued by the IASB.

Emphasis of matter – significant uncertainty over provisions and contingencies related to the Gulf of Mexico oil spill

In forming our opinion we have considered the adequacy of the disclosures made in Notes 2, 36 and 43 to the financial statements concerning the provisions, future expenditures for which reliable estimates cannot be made and other contingencies related to the Gulf of Mexico oil spill significant event. The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors. Furthermore, significant uncertainty exists in relation to the amount of claims that will become payable by BP, the amount of fines that will ultimately be levied on BP (including any determination of BP's culpability based on any findings of negligence, gross negligence or wilful misconduct), the outcome of litigation and arbitration proceedings, and any costs arising from any longer-term environmental consequences of the oil spill, which will also impact upon the ultimate cost for BP. Our opinion is not qualified in respect of these matters.

Opinion on other matter prescribed by the Companies Act 2006

In our opinion the information given in the Directors' Report for the financial year for which the consolidated financial statements are prepared is consistent with the consolidated financial statements.

Matters on which we are required to report by exception

We have nothing to report in respect of the following:

Under the Companies Act 2006 we are required to report to you if, in our opinion:

- certain disclosures of directors' remuneration specified by law are not made; or
- we have not received all the information and explanations we require for our audit.

Under the Listing Rules we are required to review:

- the directors' statement, set out on page 178, in relation to going concern;
- the part of the Governance and Risk section of the Annual report relating to the company's compliance with the nine provisions of the UK Corporate Governance Code specified for our review; and
- certain elements of the report to shareholders by the Board on directors' remuneration.

Other matter

We have reported separately on the parent company financial statements of BP p.l.c. for the year ended 31 December 2012 and on the information in the Directors' Remuneration Report that is described as having been audited.

Ernst & Young LLP
Allister Wilson (Senior Statutory Auditor)
for and on behalf of Ernst & Young LLP, Statutory Auditor
London
6 March 2013

1. The maintenance and integrity of the BP p.l.c. website are the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

This page does not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm on the Annual Report on Form 20-F

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 at 31 December 2012 and 2011, and the related group income statement, group statement of comprehensive income, group statement of changes in equity and group cash flow statement for each of the three years in the period ended 31 December 2012. 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 2012 and 2011, and the group results of its operations and its cash flows for each of the three years in the period ended 31 December 2012, 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.

In forming our opinion we have considered the adequacy of the disclosures made in Notes 2, 36 and 43 to the financial statements concerning the provisions, future expenditures for which reliable estimates cannot be made and other contingencies related to the Gulf of Mexico oil spill significant event. The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors. Furthermore, significant uncertainty exists in relation to the amount of claims that will become payable by BP, the amount of fines that will ultimately be levied on BP (including any determination of BP's culpability based on any findings of negligence, gross negligence or wilful misconduct), the outcome of litigation and arbitration proceedings, and any costs arising from any longer-term environmental consequences of the oil spill, which will also impact upon the ultimate cost for BP. Our opinion is not qualified in respect of these matters.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), BP p.l.c.'s internal control over financial reporting as at 31 December 2012, based on criteria established in Internal Control: Revised Guidance for Directors on the Combined Code as issued by the Institute of Chartered Accountants in England and Wales (the Turnbull guidance) and our report dated 6 March 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP
London, United Kingdom
6 March 2013

1. The maintenance and integrity of the BP p.l.c. website are the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm on the Annual Report on Form 20-F

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 at 31 December 2012, based on criteria established in Internal Control: Revised Guidance for Directors on the Combined Code as issued by the Institute of Chartered Accountants in England and Wales (the Turnbull guidance). 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 on page 149. 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 at 31 December 2012, based on the Turnbull guidance.

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 at 31 December 2012 and 2011, and the related group income statement, group statement of comprehensive income, group statement of changes in equity and group cash flow statement for each of the three years in the period ended 31 December 2012, and our report dated 6 March 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP
London, United Kingdom
6 March 2013

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 6 March 2013, 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 and Form 20-F for the year ended 31 December 2012 in the following Registration Statements:

> Registration Statements on Form F-3 (File No. 333-179953, 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, 333-103924, 333-123482, 333-123483, 333-131583, 333-146868, 333-146870, 333-146873, 333-131584, 333-132619, 333-173136, 333-177423, 333-179406, 333-186463 and 333-186462) of BP p.l.c.

/s/ Ernst & Young LLP
Ernst & Young LLP
London, United Kingdom
6 March 2013

1. The maintenance and integrity of the BP p.l.c. website are the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

Group income statement

For the year ended 31 December				$ million
	Note	**2012**	2011	2010
Sales and other operating revenues	6	**375,580**	375,517	297,107
Earnings from jointly controlled entities – after interest and tax	24	**744**	1,304	1,175
Earnings from associates – after interest and tax	25	**3,675**	4,916	3,582
Interest and other income	7	**1,590**	596	681
Gains on sale of businesses and fixed assets	5	**6,696**	4,130	6,383
Total revenues and other income		**388,285**	386,463	308,928
Purchases	28	**293,242**	285,618	216,211
Production and manufacturing expenses[a]		**33,911**	24,145	64,615
Production and similar taxes	8	**8,158**	8,280	5,244
Depreciation, depletion and amortization	9	**12,481**	11,135	11,164
Impairment and losses on sale of businesses and fixed assets	5	**6,275**	2,058	1,689
Exploration expense	15	**1,475**	1,520	843
Distribution and administration expenses	11	**13,357**	13,958	12,555
Fair value (gain) loss on embedded derivatives	33	**(347)**	(68)	309
Profit (loss) before interest and taxation		**19,733**	39,817	(3,702)
Finance costs[a]	17	**1,125**	1,246	1,170
Net finance expense (income) relating to pensions and other post-retirement benefits	37	**(201)**	(263)	(47)
Profit (loss) before taxation		**18,809**	38,834	(4,825)
Taxation[a]	18	**6,993**	12,737	(1,501)
Profit (loss) for the year		**11,816**	26,097	(3,324)
Attributable to				
BP shareholders	39	**11,582**	25,700	(3,719)
Minority interest	39	**234**	397	395
		11,816	26,097	(3,324)
Earnings per share – cents				
Profit (loss) for the year attributable to BP shareholders				
Basic	20	**60.86**	135.93	(19.81)
Diluted	20	**60.45**	134.29	(19.81)

[a] See Note 2 for information on the impact of the Gulf of Mexico oil spill on these income statement line items.

Group statement of comprehensive income

For the year ended 31 December				$ million
	Note	**2012**	2011	2010
Profit (loss) for the year		**11,816**	26,097	(3,324)
Currency translation differences		**531**	(531)	259
Exchange (gains) or losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets		**(15)**	19	(20)
Actuarial loss relating to pensions and other post-retirement benefits	37	**(2,335)**	(5,960)	(320)
Available-for-sale investments marked to market		**306**	(71)	(191)
Available-for-sale investments – recycled to the income statement		**(1)**	(3)	(150)
Cash flow hedges marked to market	33	**1,466**	44	(65)
Cash flow hedges – recycled to the income statement	33	**62**	(195)	(25)
Cash flow hedges – recycled to the balance sheet	33	**19**	(13)	53
Share of equity-accounted entities' other comprehensive income, net of tax		**(98)**	(57)	–
Taxation	18, 39	**446**	1,659	(137)
Other comprehensive income		**381**	(5,108)	(596)
Total comprehensive income		**12,197**	20,989	(3,920)
Attributable to				
BP shareholders	39	**11,959**	20,605	(4,318)
Minority interest	39	**238**	384	398
		12,197	20,989	(3,920)

Group statement of changes in equity[a]

$ million

	Share capital and capital reserves	Own shares and treasury shares	Foreign currency translation reserve	Fair value reserves	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
At 1 January 2012	**43,454**	**(21,323)**	**4,422**	**267**	**1,582**	**83,063**	**111,465**	**1,017**	**112,482**
Profit for the year	**–**	**–**	**–**	**–**	**–**	**11,582**	**11,582**	**234**	**11,816**
Other comprehensive income	**–**	**–**	**665**	**1,508**	**–**	**(1,796)**	**377**	**4**	**381**
Total comprehensive income	**–**	**–**	**665**	**1,508**	**–**	**9,786**	**11,959**	**238**	**12,197**
Dividends	**–**	**–**	**–**	**–**	**–**	**(5,294)**	**(5,294)**	**(82)**	**(5,376)**
Share-based payments (net of tax)	**59**	**269**	**–**	**–**	**26**	**(70)**	**284**	**–**	**284**
Transactions involving minority interests	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**33**	**33**
At 31 December 2012	**43,513**	**(21,054)**	**5,087**	**1,775**	**1,608**	**87,485**	**118,414**	**1,206**	**119,620**
At 1 January 2011	43,448	(21,211)	4,937	469	1,586	65,758	94,987	904	95,891
Profit for the year	–	–	–	–	–	25,700	25,700	397	26,097
Other comprehensive income	–	–	(515)	(202)	–	(4,378)	(5,095)	(13)	(5,108)
Total comprehensive income	–	–	(515)	(202)	–	21,322	20,605	384	20,989
Dividends	–	–	–	–	–	(4,072)	(4,072)	(245)	(4,317)
Share-based payments (net of tax)	6	(112)	–	–	(4)	102	(8)	–	(8)
Transactions involving minority interests	–	–	–	–	–	(47)	(47)	(26)	(73)
At 31 December 2011	43,454	(21,323)	4,422	267	1,582	83,063	111,465	1,017	112,482
At 1 January 2010	43,304	(21,517)	4,811	776	1,584	72,655	101,613	500	102,113
Profit (loss) for the year	–	–	–	–	–	(3,719)	(3,719)	395	(3,324)
Other comprehensive income	–	–	126	(307)	–	(418)	(599)	3	(596)
Total comprehensive income	–	–	126	(307)	–	(4,137)	(4,318)	398	(3,920)
Dividends	–	–	–	–	–	(2,627)	(2,627)	(315)	(2,942)
Share-based payments (net of tax)	144	306	–	–	2	(113)	339	–	339
Transactions involving minority interests	–	–	–	–	–	(20)	(20)	321	301
At 31 December 2010	43,448	(21,211)	4,937	469	1,586	65,758	94,987	904	95,891

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[a] See Note 39 for further information.

Group balance sheet

At 31 December

$ million

	Note	**2012**	2011
Non-current assets			
Property, plant and equipment	21	**120,448**	119,214
Goodwill	22	**11,861**	12,100
Intangible assets	23	**24,041**	21,102
Investments in jointly controlled entities	24	**15,724**	15,518
Investments in associates	25	**2,998**	13,291
Other investments	27	**2,702**	2,633
Fixed assets		**177,774**	183,858
Loans		**695**	884
Trade and other receivables	29	**4,754**	4,337
Derivative financial instruments	33	**4,294**	5,038
Prepayments		**809**	739
Deferred tax assets	18	**874**	611
Defined benefit pension plan surpluses	37	**12**	17
		189,212	195,484
Current assets			
Loans		**247**	244
Inventories	28	**27,867**	25,661
Trade and other receivables	29	**37,664**	43,526
Derivative financial instruments	33	**4,507**	3,857
Prepayments		**1,058**	1,286
Current tax receivable		**456**	235
Other investments	27	**319**	288
Cash and cash equivalents	30	**19,548**	14,067
		91,666	89,164
Assets classified as held for sale	4	**19,315**	8,420
		110,981	97,584
Total assets		**300,193**	293,068
Current liabilities			
Trade and other payables	32	**47,154**	52,405
Derivative financial instruments	33	**2,658**	3,220
Accruals		**6,810**	5,932
Finance debt	34	**10,030**	9,044
Current tax payable		**2,501**	1,941
Provisions	36	**7,587**	11,238
		76,740	83,780
Liabilities directly associated with assets classified as held for sale	4	**846**	538
		77,586	84,318
Non-current liabilities			
Other payables	32	**2,102**	3,437
Derivative financial instruments	33	**2,723**	3,773
Accruals		**448**	389
Finance debt	34	**38,767**	35,169
Deferred tax liabilities	18	**15,064**	15,078
Provisions	36	**30,334**	26,404
Defined benefit pension plan and other post-retirement benefit plan deficits	37	**13,549**	12,018
		102,987	96,268
Total liabilities		**180,573**	180,586
Net assets		**119,620**	112,482
Equity			
BP shareholders' equity	39	**118,414**	111,465
Minority interest	39	**1,206**	1,017
Total equity	39	**119,620**	112,482

R W Dudley Group Chief Executive
6 March 2013

Group cash flow statement

For the year ended 31 December				$ million
	Note	**2012**	2011	2010
Operating activities				
Profit (loss) before taxation[a]		**18,809**	38,834	(4,825)
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities				
Exploration expenditure written off	15	**745**	1,024	375
Depreciation, depletion and amortization	9	**12,481**	11,135	11,164
Impairment and (gain) loss on sale of businesses and fixed assets	5	**(421)**	(2,072)	(4,694)
Earnings from jointly controlled entities and associates		**(4,419)**	(6,220)	(4,757)
Dividends received from jointly controlled entities and associates		**2,210**	5,381	3,277
Interest receivable		**(295)**	(198)	(277)
Interest received		**181**	216	205
Finance costs	17	**1,125**	1,246	1,170
Interest paid		**(1,154)**	(1,110)	(912)
Net finance expense (income) relating to pensions and other post-retirement benefits	37	**(201)**	(263)	(47)
Share-based payments		**156**	(88)	197
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans		**(857)**	(1,004)	(959)
Net charge for provisions, less payments		**5,340**	2,976	19,217
(Increase) decrease in inventories		**(1,797)**	(3,988)	(3,895)
(Increase) decrease in other current and non-current assets		**2,968**	(9,913)	(15,620)
Increase (decrease) in other current and non-current liabilities		**(8,022)**	(5,767)	20,607
Income taxes paid		**(6,452)**	(8,035)	(6,610)
Net cash provided by operating activities		**20,397**	22,154	13,616
Investing activities				
Capital expenditure		**(23,078)**	(17,845)	(18,421)
Acquisitions, net of cash acquired		**(116)**	(10,909)	(2,468)
Investment in jointly controlled entities		**(1,530)**	(857)	(461)
Investment in associates		**(54)**	(55)	(65)
Proceeds from disposals of fixed assets	5	**9,991**	3,500	7,492
Proceeds from disposals of businesses, net of cash disposed[b]	5	**1,455**	(768)	9,462
Proceeds from loan repayments		**370**	301	501
Net cash used in investing activities		**(12,962)**	(26,633)	(3,960)
Financing activities				
Net issue of shares		**122**	74	169
Proceeds from long-term financing		**11,087**	11,600	11,934
Repayments of long-term financing		**(7,177)**	(9,102)	(4,702)
Net increase (decrease) in short-term debt		**(674)**	2,227	(3,619)
Dividends paid				
BP shareholders		**(5,294)**	(4,072)	(2,627)
Minority interest		**(82)**	(245)	(315)
Net cash provided by (used in) financing activities		**(2,018)**	482	840
Currency translation differences relating to cash and cash equivalents		**64**	(492)	(279)
Increase (decrease) in cash and cash equivalents		**5,481**	(4,489)	10,217
Cash and cash equivalents at beginning of year		**14,067**	18,556	8,339
Cash and cash equivalents at end of year		**19,548**	14,067	18,556

[a] 2012 includes $709 million of dividends received from TNK-BP. See Note 4 for further information.

[b] 2010 included a deposit received in advance of $3,530 million in respect of the expected sale of our interest in Pan American Energy LLC; 2011 included the repayment of the same amount following the termination of the sale agreement.

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 2012 were approved and signed by the group chief executive on 6 March 2013 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), IFRS as adopted by the European Union (EU) and in accordance with the provisions of the UK Companies Act 2006. 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 IFRS Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2012. The standards and interpretations adopted in the year are described further on page 192.

The accounting policies that follow have been consistently applied to all years presented.

Subsequent to releasing our unaudited fourth quarter and full year 2012 results announcement dated 5 February 2013, an adjustment of $0.8 billion has been made to provisions relating to the Gulf of Mexico oil spill as at 31 December 2012, with a corresponding adjustment to the reimbursement asset. There was no impact on profit or loss for the year. For further information see Note 36. In addition, an adjustment has been made to correct a $4.7 billion understatement of revenue and purchases for the year ended 31 December 2012. There was no impact on profit or loss for the year.

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 171-174, 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. Intercompany balances and transactions, including unrealized profits arising from intragroup transactions, have been eliminated. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred. Minority interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to 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. With effect from 1 January 2012, the former Exploration and Production segment was separated to form two new operating segments, Upstream and TNK-BP, reflecting the way in which our investment in TNK-BP is managed. In addition, we began reporting the Refining and Marketing segment as Downstream.

On 22 October 2012, BP announced that it had signed heads of terms for a proposed transaction to sell its 50% share in TNK-BP to Rosneft. Following this agreement, BP's investment in TNK-BP met the criteria to be classified as held for sale. See Note 4 for further information.

During 2010 a separate organization was created within the group to deal with the ongoing response to the Gulf of Mexico oil spill. This organization reports directly to the group chief executive officer and its costs are excluded from the results of the operating segments. Under IFRS its costs are therefore presented as a reconciling item between the sum of the results of the reportable segments and the group results.

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 6.

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 that have the characteristics of equity financing 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 associate respectively, or when the interest becomes classified as an asset held for sale.

Certain of the group's activities, particularly in the Upstream 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 incurred jointly with the other partners, along with the group's income from the sale of its share of the output and any liabilities and expenses that the group has incurred in relation to the venture.

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

The 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 subsidiaries, jointly controlled entities and associates, 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 other comprehensive income. On disposal or partial 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

A business combination is a transaction or other event in which an acquirer obtains control of one or more businesses. A business is an integrated set of activities and assets that is capable of being conducted and managed for the purpose of providing a return in the form of dividends or lower costs or other economic benefits directly to investors or other owners or participants. A business consists of inputs and processes applied to those inputs that have the ability to create outputs.

Business combinations are accounted for using the acquisition method. The identifiable assets acquired and liabilities assumed are measured at their fair values at the acquisition date. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition-date fair value, and the amount of any minority interest in the acquiree. Minority interests are stated either at fair value or at the proportionate share of the recognized amounts of the acquiree's identifiable net assets. Acquisition costs incurred are expensed and included in distribution and administration expenses.

Goodwill is initially measured as the excess of the aggregate of the consideration transferred, the amount recognized for any minority interest and the acquisition-date fair values of any previously held interest in the acquiree over the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date.

At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units, or groups of cash-generating units, expected to benefit from the combination's synergies.

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. An impairment loss recognized for goodwill is not reversed in a subsequent period.

Goodwill arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount, less subsequent impairments, 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 and liabilities. Such goodwill is recorded within investments in jointly controlled entities and associates, and any impairment of the investment is included within the group's share of 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 subject only to terms that are usual and customary for sales of such assets. 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 as held for sale.

Property, plant and equipment and intangible assets are not depreciated once classified as held for sale. The group ceases to use the equity method of accounting from the date on which an interest in a jointly controlled entity or an interest in an associate becomes held for sale. If a non-current asset or disposal group has been classified as held for sale, but subsequently ceases to meet the criteria to be classified as held for sale, the group ceases to classify the asset or disposal group as held for sale. Non-current assets and disposal groups that cease to be classified as held for sale are measured at the lower of the carrying amount before the asset or disposal group was classified as held for sale (adjusted for any depreciation, amortization or revaluation that would have been recognized had the asset or disposal group not been classified as held for sale) and its recoverable amount at the date of the subsequent decision not to sell. Except for any interests in equity-accounted entities that cease to be classified as held for sale, any adjustment to the carrying amount is recognized in profit or loss in the period in which the asset ceases to be classified as held for sale. When an interest in an equity-accounted entity ceases to be classified as held for sale, it is accounted for using the equity method as from the date of its classification as held for sale and the financial statements for the periods since classification as held for sale are amended accordingly.

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. For information on accounting for expenditures on the exploration for and evaluation of oil and gas resources, see the accounting policy for oil and natural gas exploration, appraisal and development expenditure below.

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.

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 generally have a useful life of three to five years.

1. Significant accounting policies continued

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.

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 and payments made to contractors. If potentially commercial quantities of hydrocarbons are not found, the exploration well 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 and 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 the location and condition necessary for it to be capable of operating in the manner intended by management, 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, and 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, common facilities and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the amortization of common facilities costs takes into account expenditures incurred to date, together with the future capital expenditure expected to be incurred in relation to these common facilities.

Other property, plant and equipment is depreciated on a straight line basis over its expected useful life. The typical 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 amount 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.

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 amount of an asset may not be recoverable, for example, changes in the group's business plans, changes in commodity prices leading to sustained unprofitable performance, low plant utilization, evidence of physical damage 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 an indication exists, the recoverable

1. Significant accounting policies continued

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 or financial assets at fair value through profit or loss. 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

Financial assets at fair value through profit or loss are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category.

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 fair 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.

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, most items of 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

Financial liabilities at fair value through profit or loss are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category.

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.

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 income 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 item 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.

1. Significant accounting policies continued

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 relating to unquoted equity instruments are carried at cost where it is not possible to reliably measure their fair value subsequent to initial recognition. 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. Contracts to buy or sell equity investments, including investments in associates, are also 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.

Hedge relationships are formally designated and documented at inception, 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 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 other comprehensive income 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. Where the hedged item is an equity investment, such as an investment in an associate, the amounts recognized in other comprehensive income remain in the separate component of equity until the investment is sold or impaired.

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.

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, contingencies and reimbursement assets

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 risk-free 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. Provisions are split between amounts expected to be settled within 12 months of the balance sheet date (current) and amounts expected to be settled later (non-current). Contingent liabilities are possible obligations whose existence will only be confirmed by future events not wholly within the control of the group, or present obligations where it is not probable that an outflow of resources will be required or the amount of the obligation cannot be measured with sufficient reliability.

Contingent liabilities are not recognized in the financial statements but are disclosed unless the possibility of an outflow of economic resources is considered remote.

Where the group makes contributions into a separately administered fund for restoration, environmental or other obligations, which it does not control, and the group's right to the assets in the fund is restricted, the obligation to contribute to the fund is recognized as a liability where it is probable that such additional contributions will be made. The group recognizes a reimbursement asset separately, being the lower of the amount of the associated restoration, environmental or other provision and the group's share of the fair value of the net assets of the fund available to contributors.

Decommissioning

Liabilities for decommissioning costs are recognized when the group has an obligation to plug and abandon a well, 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 or item of plant, such as oil and natural gas production or transportation facilities, this liability will be recognized on construction or installation. Similarly, where an obligation exists for a well, this liability is recognized when it is drilled. An obligation for decommissioning may also crystallize during the period of operation of a well, facility or item of plant 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 intangible asset (in the case of an exploration or appraisal well) or item of property, plant and equipment of an amount equivalent to the provision is also recognized. The item of property, plant and equipment is subsequently depreciated as part of the asset.

1. Significant accounting policies continued

Other than the unwinding of 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 asset. 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 that 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 policies for share-based payments and for pensions and other post-retirement benefits are 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.

Cash-settled transactions

The cost of cash-settled transactions is measured at fair value at each balance sheet date and recognized as an expense over the vesting period, with a corresponding liability for the cumulative expense 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 plan 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 plan 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 forecasts 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 year 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 plans are recognized in the income statement in the period in which they become payable.

Corporate taxes

Income tax expense represents the sum of current tax and deferred tax. Interest and penalties relating to tax are also included in income tax expense.

Income tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity, in which case the related tax is recognized in other comprehensive income or directly in equity.

Current tax is based on the taxable profit for the period. Taxable profit differs from net profit as reported in the income statement because it is determined in accordance with the rules established by the applicable taxation authorities. It therefore excludes items of income or expense that are taxable or deductible in other periods as well as items that are never taxable or deductible. The group's liability for current tax is calculated using tax rates and laws 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 the initial recognition of goodwill; or

1. Significant accounting policies continued

- Where the deferred tax liability arises on 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 accounting profit nor taxable profit or loss; or
- In respect of taxable temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, 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 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 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 tax asset to be utilized.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period 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. Deferred tax assets and liabilities are not discounted.

Deferred tax assets and liabilities are offset only when there is a legally enforceable right to set off current tax assets against current tax liabilities and when the deferred tax assets and liabilities relate to income taxes levied by the same taxation authority on either the same taxable entity or different taxable entities where there is an intention to settle the current tax assets and liabilities on a net basis or to realize the assets and settle the liabilities simultaneously.

Customs duties and sales taxes

Customs duties and sales taxes which are passed on to customers are excluded from revenues and expenses. Assets and liabilities 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.
- 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 within 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.

Revenue

Revenue arising from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer, which is typically at the point that title passes, and the revenue 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.

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 2012

There are no new or amended standards or interpretations adopted with effect from 1 January 2012 that have a 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.

Interests in other entities and related disclosures

In May 2011, the IASB issued three new standards relating to interests in other entities and related disclosures. The new standards are IFRS 10 'Consolidated Financial Statements', IFRS 11 'Joint Arrangements' and IFRS 12 'Disclosure of Interests in Other Entities'. In addition, the IASB issued amendments to IAS 27 'Consolidated and Separate Financial Statements' (renamed IAS 27 'Separate Financial Statements') and IAS 28 'Investments in Associates' (renamed IAS 28 'Investments in Associates and Joint Ventures').

IFRS 10 introduces a single consolidation model that identifies control as the basis for consolidation. The new model applies to all types of entities, including structured entities. Under the new model, an investor controls an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee.

1. Significant accounting policies continued

IFRS 11 establishes a principle that applies to the accounting for all joint arrangements, whereby parties to the arrangement account for their underlying contractual rights and obligations relating to the joint arrangement. IFRS 11 identifies two types of joint arrangements. A 'joint venture' is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. A 'joint operation' is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Investments in joint ventures will be accounted for using the equity method. Investments in joint operations will be accounted for by recognizing the group's assets, liabilities, revenue and expenses relating to the joint operation.

IFRS 12 combines all the disclosure requirements for an entity's interests in subsidiaries, joint arrangements, associates and structured entities into one comprehensive disclosure standard.

These new and amended standards are effective for annual periods beginning on or after 1 January 2013 and BP will adopt them from this date. The evaluation of the effect of adoption of these standards is largely complete. The main impact of this suite of new standards is that certain of the group's existing jointly controlled entities, which are currently equity accounted, will fall under the definition of a joint operation under IFRS 11 and thus we will recognize the group's assets, liabilities, revenue and expenses relating to these arrangements. Whilst the effect on the group's reported income and net assets as a result of the new requirements is not expected to be material, the change is expected to materially impact certain of the component lines of the balance sheet and income statement. On the balance sheet, we expect a reduction in investments in jointly controlled entities of approximately $7 billion, which will be replaced with the recognition (on the relevant line items, principally intangible assets and property, plant and equipment) of our share of the assets and liabilities relating to these arrangements. In the income statement, we expect a reduction in earnings from jointly controlled entities of approximately $0.5 billion, which will be replaced with the recognition (on the relevant line items) of our share of the revenue and expenses relating to these arrangements.

This new suite of standards was adopted by the EU in December 2012.

Other new standards not yet adopted

In June 2011, the IASB issued an amended version of IAS 19 'Employee Benefits', which brings in various changes relating to the recognition and measurement of post-retirement defined benefit expense and termination benefits, and to the disclosures for all employee benefits. The main impact for BP will be that the expense for defined benefit pension and other post-retirement benefit plans will include a net interest income or expense, which will be calculated by applying the discount rate used for measuring the obligation and applying that to the net defined benefit asset or liability. This means that the expected return on assets credited to profit or loss (currently calculated based on the expected long-term return on pension assets) will now be based on a lower corporate bond rate, the same rate that is used to discount the pension liability. The amended IAS 19 is effective for annual periods beginning on or after 1 January 2013 and BP will adopt this amended standard from that date. The evaluation of the effect of adoption of the amended standard is largely complete. Under the amended IAS 19, net finance expense (income) relating to pensions and other post-retirement benefits and profit before tax would have been approximately $0.8 billion and $0.7 billion lower for 2012 and 2011 respectively, with corresponding pre-tax increases in other comprehensive income. There is no impact on cash flows or on the balance sheet at 31 December 2012.

In May 2011, the IASB issued a new standard, IFRS 13 'Fair Value Measurement'. The new standard defines fair value, sets out a framework for measuring fair value and contains the required disclosures about fair value measurements. IFRS 13 does not require fair value measurements in addition to those already required or permitted by other standards, rather it prescribes how fair value should be measured if another standard requires it. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date i.e. it is an exit price. IFRS 13 is effective for annual periods beginning on or after 1 January 2013 and BP will adopt it from this date. For BP, no significant impact is expected as a result of the adoption of IFRS 13.

In December 2011, the IASB issued amendments to IFRS 7 'Disclosures – Offsetting Financial Assets and Financial Liabilities' and amendments to IAS 32 'Offsetting Financial Assets and Financial Liabilities'. These amendments introduce new presentation and disclosure requirements about the effects of offsetting financial assets and financial liabilities and related arrangements on an entity's financial position. The amendments to IFRS 7 are effective for annual periods beginning on or after 1 January 2013, with the amendments to IAS 32 effective for annual periods beginning on or after 1 January 2014. BP will adopt these amendments with effect from 1 January 2013 and 1 January 2014 respectively. As a result of the amendments to IFRS 7, the notes to BP's 2013 financial statements will disclose additional information on gross and net financial instruments balances. The evaluation of the effect of adoption of the amendments to IAS 32 is not expected to result in any significant changes to the offsetting of financial assets and liabilities.

In June 2011, the IASB issued amendments to IAS 1 'Presentation of Financial Statements' on the presentation of other comprehensive income (OCI). The amendments require that those items of OCI that might be reclassified to profit or loss at a future date be presented separately from those items that will never be reclassified to profit or loss. These amendments to IAS 1 are effective for annual periods beginning on or after 1 July 2012. BP will adopt the amendments with effect from 1 January 2013. The adoption of the amended standard will have a presentational impact on the group's statement of comprehensive income, with no effect on the reported income or net assets of the group.

As part of the IASB's project to replace IAS 39 'Financial Instruments: Recognition and Measurement', in November 2009 the IASB issued the first phase of IFRS 9 'Financial Instruments', dealing with the classification and measurement of financial assets. In October 2010, the IASB updated IFRS 9 by incorporating the requirements for the accounting for financial liabilities. The remaining phases of IFRS 9 (covering impairment and hedge accounting) are still to be completed. In December 2011, the IASB decided that IFRS 9 will be effective for annual periods beginning on or after 1 January 2015, rather than 1 January 2013 as originally indicated. BP has not yet decided the date of adoption for the group and has not yet completed its evaluation of the effect of adoption.

With the exception of IFRS 9, the EU has now adopted all of the above-mentioned other new standards that have been issued but not yet adopted by the group.

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.

2. Significant event – Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill, as described on pages 59-62, BP continues to incur costs and has also recognized liabilities for future costs. Liabilities of uncertain timing or amount and contingent liabilities have been accounted for and/or disclosed in accordance with IAS 37 'Provisions, Contingent Liabilities and Contingent Assets'. These are discussed in further detail in Note 36 for provisions and Note 43 for contingent liabilities. BP's rights and obligations in relation to the $20-billion trust fund which was established in 2010 are accounted for in accordance with IFRIC 5 'Rights to Interests Arising from Decommissioning, Restoration and Environmental Rehabilitation Funds'. Key aspects of the accounting for the oil spill are summarized below.

The financial impacts of the Gulf of Mexico oil spill on the income statement, balance sheet and cash flow statement of the group are shown in the table below. Amounts related to the trust fund are separately identified.

The cumulative income statement charge does not include amounts for obligations that BP considers are not possible, at this time, to measure reliably. For further information see Note 43.

The total amounts that will ultimately be paid by BP in relation to all the obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors, as discussed in Note 43, including in relation to any new information or future developments. These could have a material impact on our consolidated financial position, results of operations and cash flows. The risks associated with the incident could also heighten the impact of the other risks to which the group is exposed as further described in Risk factors on pages 38-44.

						$ million
		2012		2011		2010
	Total	**Of which: amount related to the trust fund**	Total	Of which: amount related to the trust fund	Total	Of which: amount related to the trust fund
Income statement						
Production and manufacturing expenses	**4,995**	**(1,191)**	(3,800)	(3,995)	40,858	7,261
Profit (loss) before interest and taxation	**(4,995)**	**1,191**	3,800	3,995	(40,858)	(7,261)
Finance costs	**19**	**12**	58	52	77	73
Profit (loss) before taxation	**(5,014)**	**1,179**	3,742	3,943	(40,935)	(7,334)
Less: taxation	**94**	**–**	(1,387)	–	12,894	–
Profit (loss) for the period	**(4,920)**	**1,179**	2,355	3,943	(28,041)	(7,334)
Balance sheet						
Current assets						
Trade and other receivables	**4,239**	**4,178**	8,487	8,233	5,943	5,943
Current liabilities						
Trade and other payables	**(522)**	**(22)**	(5,425)	(4,872)	(6,587)	(5,002)
Provisions	**(5,449)**	**–**	(9,437)	–	(7,938)	–
Net current liabilities	**(1,732)**	**4,156**	(6,375)	3,361	(8,582)	941
Non-current assets						
Other receivables	**2,264**	**2,264**	1,642	1,642	3,601	3,601
Non-current liabilities						
Other payables	**(175)**	**–**	–	–	(9,899)	(9,899)
Provisions	**(9,751)**	**–**	(5,896)	–	(8,397)	–
Deferred tax	**4,002**	**–**	7,775	–	11,255	–
Net non-current liabilities	**(3,660)**	**2,264**	3,521	1,642	(3,440)	(6,298)
Net assets	**(5,392)**	**6,420**	(2,854)	5,003	(12,022)	(5,357)
Cash flow statement						
Profit (loss) before taxation	**(5,014)**	**1,179**	3,742	3,943	(40,935)	(7,334)
Finance costs	**19**	**12**	58	52	77	73
Net charge for provisions, less payments	**4,834**	**–**	2,699	–	19,354	–
(Increase) decrease in other current and non-current assets	**(998)**	**(1,191)**	(4,292)	(4,038)	(12,567)	(12,567)
Increase (decrease) in other current and non-current liabilities	**(5,090)**	**(4,860)**	(11,113)	(10,097)	16,413	14,828
Pre-tax cash flows	**(6,249)**	**(4,860)**	(8,906)	(10,140)	(17,658)	(5,000)

The impact on net cash provided by operating activities, on a post-tax basis, amounted to $2,382 million (2011 $6,813 million and 2010 $16,019 million).

Trust fund

In 2010, BP established the Deepwater Horizon Oil Spill Trust (the Trust) to be funded in the amount of $20 billion (the trust fund) over the period to the fourth quarter of 2013, which is available to satisfy legitimate individual and business claims that were previously administered by the Gulf Coast Claims Facility (GCCF), state and local government claims resolved by BP, final judgments and settlements, state and local response costs, and natural resource damages and related costs. The Trust is available to satisfy claims that were previously processed through the transitional court-supervised claims facility, to fund the qualified settlement funds (QSFs) established under the terms of the settlement agreements with the Plaintiffs' Steering Committee (PSC) administered through the Deepwater Horizon Court Supervised Settlement Program (DHCSSP), and the separate BP claims programme – see below for further information. Fines, penalties and claims administration costs are not covered by the trust fund. The establishment of the trust fund does not represent a cap or floor on BP's liabilities and BP does not admit to a liability of this amount.

In 2010, BP contributed $5 billion to the fund, and further regular contributions totalling $5 billion were made in 2011. During 2011, BP also contributed the cash settlements received from MOEX, Weatherford and Anadarko, amounting in total to $5.1 billion. A further cash settlement from Cameron was received in January 2012 and was also contributed to the trust fund. As a result of these accelerated contributions and BP's regular contributions, the $20-billion commitment was paid in full during 2012. The income statement charge for 2010 included $20 billion in relation to the trust fund, adjusted to take account of the time value of money.

2. Significant event – Gulf of Mexico oil spill continued

Under the terms of the Trust agreement, BP has no right to access the funds once they have been contributed to the trust fund and BP has no decision-making role in connection with the payment by the trust fund of individual and business claims resolved by the GCCF and the new court-supervised claims processes referred to below. BP will receive funds from the trust fund only upon its expiration, if there are any funds remaining at that point. Any amount remaining in the trust fund when the trustees determine that all claims have been settled would be returned to BP. However, it is not possible to reliably estimate the number or total amount of the claims that will be settled from the trust fund, and therefore it is not possible to reliably measure the fair value of BP's residual interest in it. The carrying amount of BP's residual interest is, consequently, nil. BP has the authority under the Trust agreement to present certain resolved claims, including natural resource damages claims and state and local response claims, to the Trust for payment, by providing the trustees with all the required documents establishing that such claims are valid under the Trust agreement. However, any such payments can only be made on the authority of the trustees and any funds distributed are paid directly to the claimants, not to BP. BP will not settle any such items directly or receive reimbursement from the trust fund for such items.

BP's obligation to make contributions to the trust fund was recognized in full in 2010, amounting to $20 billion on an undiscounted basis. On initial recognition the discounted amount recognized was $19,580 million. The funding of the Trust has now been completed.

The table below shows movements in the funding obligation during the period to 31 December 2012. The remaining liability of $22 million at 31 December 2012 represents amounts reimbursable to the Trust for administrative costs incurred.

			$ million
	2012	2011	2010
At 1 January	**4,872**	14,901	–
Trust fund liability initially recognized – discounted	**–**	–	19,580
Unwinding of discount	**12**	52	73
Change in discounting	**–**	43	240
Contributions	**(4,860)**	(10,140)	(5,000)
Other	**(2)**	16	8
At 31 December	**22**	4,872	14,901

An asset has been recognized representing BP's right to receive reimbursement from the trust fund. This is the portion of the estimated future expenditure provided for that will be settled by payments from the trust fund. We use the term 'reimbursement asset' to describe this asset. BP will not actually receive any reimbursements from the trust fund, instead payments will be made directly to claimants from the trust fund, and BP will be released from its corresponding obligation.

The provision was increased during the year for items that will be covered by the trust fund by $1,985 million (2011 $4,038 million) and payments of $4,624 million (2011 $3,707 million) were made during the year from the trust fund. This includes payments from the trust fund to the seafood compensation fund and payments from QSFs other than the seafood compensation fund to claimants. In addition, a provision of $794 million was derecognized relating to items that will be covered by the trust fund but which can no longer be reliably estimated. The remaining reimbursement asset as at 31 December 2012 was $6,442 million and is recorded within other receivables on the balance sheet. The amount of the reimbursement asset is equal to the amount of provisions as at 31 December 2012 that will be covered by the trust fund – see Note 36 in the table under Provisions relating to the Gulf of Mexico oil spill.

Movements in the reimbursement asset are presented in the table below.

			$ million
	2012	2011	2010
At 1 January	**9,875**	9,544	–
Increase in provision for items covered by the trust fund	**1,985**	4,038	12,567
Derecognition of provision for items that cannot be reliably estimated	**(794)**	–	–
Amounts paid directly by the trust fund	**(4,624)**	(3,707)	(3,023)
At 31 December	**6,442**	9,875	9,544
Of which – current	**4,178**	8,233	5,943
– non-current	**2,264**	1,642	3,601

The amount charged or credited in the income statement, before finance costs, related to the trust fund comprises:

			$ million
	2012	2011	2010
Trust fund liability – discounted	**–**	–	19,580
Change in discounting relating to trust fund liability	**–**	43	240
Recognition of reimbursement asset, net	**(1,191)**	(4,038)	(12,567)
Other	**–**	–	8
Total (credit) charge relating to the trust fund	**(1,191)**	(3,995)	7,261

As noted above, the obligation to fund the $20-billion trust fund was recognized in full in 2010, on a discounted basis. In addition, a reimbursement asset was recognized, reflecting the portion of provisions recognized that will be covered by the trust fund. Any new provisions, or increases in provisions that are covered by the trust fund (up to the amount of $20 billion) have no net income statement effect as a reimbursement asset is also recognized, as described above. During 2012, a further net charge of $1,191 million (2011 $4,038 million) was recognized for new, increased and derecognized provisions for items covered by the trust fund with a corresponding increase in the reimbursement asset, resulting in no net income statement effect. The cumulative net charges for provisions, and the associated reimbursement asset, recognized from 2010 to 2012 amounted to $17,796 million. Thus, a further $2,204 million could be provided in subsequent periods for items covered by the trust fund with no net impact on the income statement. Such future increases in amounts provided could arise from adjustments to existing provisions, or from the initial recognition of provisions for items that currently cannot be estimated reliably, namely natural resource damages claims under Oil Pollution Act of 1990 (OPA 90) (other than the estimated costs of the assessment phase and the costs of early restoration agreements referred to below), the cost of business economic loss claims under the PSC settlement not yet received or processed by the DHCSSP, or any other potential litigation (including through excluded parties from the PSC settlement and any obligation in relation to other potential private or governmental litigation). Further information on those items that currently cannot be reliably estimated is provided under Provisions and contingencies below and in Note 43.

2. Significant event – Gulf of Mexico oil spill continued

The $20-billion trust fund may not be sufficient to satisfy all claims under OPA 90 or otherwise that will ultimately be paid.

The Trust agreement does not require BP to make further contributions to the trust fund in excess of the agreed $20 billion should this be insufficient to cover all claims administered by the GCCF and the new court-supervised claims processes, or to settle other items that are covered by the trust fund, as described above. Should the $20-billion trust fund not be sufficient, BP would commence settling legitimate claims and other costs by making payments directly to claimants or directly to the QSFs, as appropriate. In this case, increases in estimated future expenditure above $20 billion would be recognized as provisions with a corresponding charge in the income statement. The provisions would be utilized and derecognized at the point that BP made the payments. Under the terms of the Economic and Property Damages Settlement Agreement, several QSFs were established during 2012. These QSFs each relate to specific elements of the agreement, have and will be funded through payments from the Trust, and are available to make payments to claimants in accordance with those elements of the agreement.

As at 31 December 2012, the cash balances in the Trust and the QSFs amounted to $10,471 million, including $1,847 million remaining in the seafood compensation fund yet to be distributed. Under the terms of the Economic and Property Damage Settlement, the QSFs are subject to certain minimum balances that shall be maintained in the respective funds.

The Economic and Property Damages Settlement with the PSC provides for a transition from the GCCF to the DHCSSP. A transitional claims facility for economic and property damages claims commenced operation in March 2012. The transitional claims facility ceased processing new claims in June 2012. The DHCSSP began processing new claims from claimants under the Economic and Property Damages Settlement. In addition, a separate BP claims programme began processing claims from claimants not in the Economic and Property Damages Settlement Class as determined by the Economic and Property Damages Settlement Agreement or who have requested to opt out of that settlement. Moreover, upon the effective date of the Medical Benefits Class Action Settlement (that is, after any appeals of the final approval of that settlement are exhausted), a separate court-supervised settlement programme will begin paying medical claims and implementing other aspects of the medical benefits settlement, such as the Periodic Medical Consultation Program. In addition, some payments to projects under the Gulf Region Health Outreach Program portion of the Medical Benefits Class Action Settlement have already been made.

BP pledged certain Gulf of Mexico assets, through an overriding royalty interest, as collateral for the obligation to fund the Trust pursuant to an agreement entered into in September 2010. As noted above, in November 2012 BP met its $20-billion funding obligation to the Trust. Upon completion of the funding obligation, the overriding royalty interest provided as collateral terminated pursuant to its terms.

Provisions and contingencies

At 31 December 2012, BP has recorded certain provisions and disclosed certain contingent liabilities as a consequence of the Gulf of Mexico oil spill. These are described below under Oil Pollution Act of 1990 and Other items.

Oil Pollution Act of 1990 (OPA 90)

The claims against BP under OPA 90 fall into three categories: (i) claims by individuals and businesses for removal costs, damage to real or personal property, lost profits or impairment of earning capacity and loss of subsistence use of natural resources (“Individual and Business Claims”); (ii) claims by state and local government entities for removal costs, physical damage to real or personal property, loss of government revenue and increased public services costs (“State and Local Claims”); and (iii) claims by the United States, a State trustee, an Indian tribe trustee, or a foreign trustee for natural resource damages (“Natural Resource Damages claims”). In addition, BP faces civil litigation in which claims for liability under OPA 90 along with other causes of actions, including personal injury claims, are asserted by individuals, businesses and government entities.

Provisions have been recorded for Individual and Business Claims and State and Local Claims, except as noted below. A provision has also been recorded for claims administration costs, natural resource damage assessment costs and costs relating to early natural resource damages restoration agreements. BP considers that it is not possible to measure reliably any obligation in relation to natural resource damage claims (other than the estimated costs of the assessment phase and the costs relating to early restoration agreements), the cost of business economic loss claims under the PSC settlement not yet received or processed by the DHCSSP, or any other potential litigation (including through excluded parties from the PSC settlement and any obligation in relation to other potential private or governmental litigation), fines, or penalties, other than as described above. These items are therefore disclosed as contingent liabilities – see Note 43 for further information.

Significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable through the claims process established pursuant to the PSC settlement. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported. In addition, there is further uncertainty in relation to interpretations of the claims administrator regarding the protocols under the Economic and Property Damages Settlement and judicial interpretation of these protocols, and the outcomes of any further litigation including in relation to potential opt-outs from the settlement or otherwise. See Note 36 for further information.

The $20-billion trust fund described above is available to satisfy the OPA 90 claims and litigation referred to above. BP’s rights and obligations in relation to the trust fund have been recognized and $20 billion, adjusted to take account of the time value of money, was charged to the income statement in 2010.

Other items

Provisions at 31 December 2012 also include amounts in relation to completing the oil spill response, BP’s commitment to a 10-year research programme in the Gulf of Mexico, the discounted cost of the agreement with the US government to settle all federal criminal charges, estimated penalties for liability under Clean Water Act Section 311 and estimated legal fees. These are not covered by the trust fund.

The provision does not reflect any amounts in relation to fines and penalties except for those relating to the Clean Water Act, as it is not possible to estimate reliably either the amount or timing of such additional items. BP also considers that it is not possible to measure reliably any obligation in relation to litigation other than as included within the settlement with the PSC as set forth in Note 36 and the settlement with the US government for federal criminal charges. These items are therefore disclosed as contingent liabilities. Further information on provisions is provided below and in Note 36. Further information on contingent liabilities is provided in Note 43.

Provision movements

A provision has been recognized for estimated future expenditure relating to the incident, for items that can be measured reliably at this time, in accordance with BP’s accounting policy for provisions, as set out in Note 1.

2. Significant event – Gulf of Mexico oil spill continued

The total amount recognized as an increase in provisions during the year was $6,868 million, including $1,985 million for items covered by the trust fund and $4,883 million for other items (2011 $5,183 million, including $4,038 million for items covered by the trust fund and $1,145 million for other items). In addition, $794 million was derecognized relating to items that will be covered by the trust fund but which can no longer be reliably estimated. After deducting amounts utilized during the year totalling $5,864 million, including payments from the trust fund of $4,624 million and payments made directly by BP of $1,240 million (2011 $6,208 million, including payments from the trust fund of $3,707 million and payments made directly by BP of $2,501 million), and after reclassifications and adjustments for discounting, the remaining provision as at 31 December 2012 was $15,200 million (2011 $15,333 million).

Movements in the provision are presented in the table below.

			$ million
	2012	2011	2010
At 1 January	**15,333**	16,335	–
Increase in provision – items not covered by the trust fund	**4,883**	1,145	17,694
– items covered by the trust fund	**1,985**	4,038	12,567
Derecognition of provision for items that cannot be reliably estimated[a]	**(794)**	–	–
Unwinding of discount	**7**	6	4
Reclassified to other payables	**(350)**	–	–
Change in discount rate	**–**	17	5
Utilization – paid by BP	**(1,240)**	(2,501)	(10,912)
– paid by the trust fund	**(4,624)**	(3,707)	(3,023)
At 31 December	**15,200**	15,333	16,335
Of which – current	**5,449**	9,437	7,938
– non-current	**9,751**	5,896	8,397

[a] Relates to items covered by the trust fund.

The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors. Furthermore, significant uncertainty exists in relation to the amount of claims that will become payable by BP, the amount of fines that will ultimately be levied on BP (including any determination of BP's culpability based on any findings of negligence, gross negligence or wilful misconduct), the outcome of litigation and arbitration proceedings, and any costs arising from any longer-term environmental consequences of the oil spill, which will also impact upon the ultimate cost for BP. The amount and timing of any amounts payable could also be impacted by any further settlements which may or may not occur.

Although the provision recognized is the current best reliable estimate of expenditures required to settle certain present obligations at the end of the reporting period, there are future expenditures for which it is not possible to measure the obligation reliably. See Note 43 for further information.

Impact upon the group income statement

The group income statement for 2012 includes a pre-tax charge of $5,014 million (2011 pre-tax credit of $3,742 million) in relation to the Gulf of Mexico oil spill. The amount charged to date comprises costs incurred up to 31 December 2012, settlements agreed with the co-owners of the Macondo well and other third parties, estimated obligations for future costs that can be estimated reliably at this time and rights and obligations relating to the trust fund. Finance costs of $19 million (2011 $58 million) reflect the unwinding of the discount on the trust fund liability and provisions. The amount of the provision recognized during the year can be reconciled to the income statement amount as follows:

			$ million
	2012	2011	2010
Net increase in provision	**6,868**	5,183	30,261
Derecognition of provision for items that cannot be reliably estimated	**(794)**	–	–
Change in discount rate relating to provisions	**–**	17	5
Costs charged directly to the income statement	**257**	512	3,339
Trust fund liability – discounted	**–**	–	19,580
Change in discounting relating to trust fund liability	**–**	43	240
Recognition of reimbursement asset, net	**(1,191)**	(4,038)	(12,567)
Settlements credited to the income statement	**(145)**	(5,517)	–
(Profit) loss before interest and taxation	**4,995**	(3,800)	40,858

Costs charged directly to the income statement relate to expenditure prior to the establishment of a provision at the end of the second quarter 2010 and ongoing operating costs of the GCRO. The accounting associated with the recognition of the trust fund liability and the expenditure which will be settled from the trust fund is described above.

2. Significant event – Gulf of Mexico oil spill continued

The total amount in the income statement is analysed in the table below. Costs charged directly to the income statement in 2010 in relation to spill response, environmental and litigation and claims are those that arose prior to recording a provision at the end of the second quarter of that year.

			$ million
	2012	2011	2010
Trust fund liability – discounted	**–**	–	19,580
Change in discounting relating to trust fund liability	**–**	43	240
Recognition of reimbursement asset, net	**(1,191)**	(4,038)	(12,567)
Other	**–**	–	8
Total (credit) charge relating to the trust fund	**(1,191)**	(3,995)	7,261
Spill response – amount provided	**109**	586	10,883
Spill response – costs charged directly to the income statement	**9**	85	2,745
Total charge relating to spill response	**118**	671	13,628
Environmental – amount provided	**801**	1,167	929
Environmental – change in discount rate relating to provisions	**–**	17	5
Environmental – costs charged directly to the income statement	**–**	–	70
Total charge relating to environmental	**801**	1,184	1,004
Litigation and claims – amount provided, net of derecognition of provision	**5,164**	3,430	14,939
Litigation and claims – costs charged directly to the income statement	**–**	–	184
Total charge relating to litigation and claims	**5,164**	3,430	15,123
Clean Water Act penalties – amount provided	**–**	–	3,510
Other costs charged directly to the income statement	**248**	427	332
Settlements credited to the income statement	**(145)**	(5,517)	–
(Profit) loss before interest and taxation	**4,995**	(3,800)	40,858
Finance costs	**19**	58	77
(Profit) loss before taxation	**5,014**	(3,742)	40,935

The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty as described above under Provisions and contingencies.

3. Business combinations

Business combinations in 2012

BP undertook a number of minor business combinations in 2012 for a total consideration of $116 million in cash. The most significant of these was the acquisition of Shell and Cosan Indústria e Commércio's interests in significant aviation fuels assets at seven Brazilian airports in the Downstream segment. Fair value adjustments were made to the acquired assets and liabilities.

Certain measurement period adjustments were recognized in 2012 relating to the Reliance transaction, a business combination undertaken in 2011 – see below for further details.

Business combinations in 2011

BP undertook a number of business combinations in 2011. Total consideration paid in cash amounted to $11.3 billion, offset by cash acquired of $0.4 billion. The fair value of contingent consideration payable amounted to $0.1 billion.

On 30 August 2011, BP acquired from Reliance Industries Limited (Reliance) a 30% interest in 21 oil and gas production-sharing agreements (PSAs) operated by Reliance in India for $7,026 million. This included the producing KG D6 block. In addition, on 17 November 2011, the companies formed a 50:50 joint venture for the sourcing and marketing of gas in India. This transaction provided BP with access to an emerging market with growth in energy demand; it builds BP's business in natural gas and it represents an important partnership with a leading national energy business.

The transaction was accounted for as a business combination using the acquisition method. During 2012, measurement period adjustments amounted to an overall decrease of $115 million in the net fair value of the identifiable assets and liabilities acquired, an increase of $46 million in the goodwill arising on acquisition and an adjustment to reduce the contingent consideration to nil.

Goodwill of $2,569 million arose on acquisition, attributed to market access and other benefits arising from the business combination.

3. Business combinations continued

The provisional fair values of the identifiable assets and liabilities acquired, as reported at 31 December 2011, are shown in the table below, together with the subsequent measurement period adjustments recognized during 2012.

$ million

	Final amounts recognized 2012	**Measurement period adjustments 2012**	Provisional amounts recognized 2011
Assets			
Property, plant and equipment	**1,860**	**–**	1,860
Intangible assets	**2,901**	**(69)**	2,970
Inventories	**55**	**–**	55
Prepayments	**5**	**–**	5
Liabilities			
Trade and other payables	**(167)**	**(22)**	(145)
Provisions	**(266)**	**(24)**	(242)
	4,388	**(115)**	4,503
Goodwill arising on acquisition	**2,569**	**46**	2,523
Total consideration	**6,957**	**(69)**	7,026

The consideration for the transaction included $6,957 million in cash, paid in 2011. In addition, contingent consideration of up to $1,800 million, dependent upon exploration success in certain of the interests resulting in the development of commercial discoveries, was agreed.

Transaction costs of $13 million were paid in 2011 and charged within production and manufacturing expenses in the group income statement.

In addition to the Reliance transaction described above, BP undertook a number of other business combinations in 2011. These included the completion of the final part of the transaction with Devon Energy (Devon), the acquisition of Devon's equity stake in a number of assets in Brazil for consideration of $3.6 billion (see below). Additionally, BP's Alternative Energy business acquired Companhia Nacional de Açúcar e Álcool (CNAA) in Brazil for consideration of $0.7 billion and increased its share in the Brazilian biofuels company, Tropical BioEnergia S.A., to 100% by acquiring the remaining 50% for consideration of $71 million. There were a number of other individually insignificant business combinations.

Business combinations in 2010

BP undertook a number of business combinations in 2010 for a total consideration of $3.6 billion, of which $3 billion comprised cash consideration. The most significant acquisition was a transaction in the Upstream segment with Devon, undertaken in a number of stages during 2010 and 2011. This transaction strengthened BP's position in the Gulf of Mexico, enhanced interests in Azerbaijan and facilitated the development of Canadian assets.

On 27 April 2010, BP acquired 100% of Devon's Gulf of Mexico deepwater properties for $1.8 billion. This included a number of exploration properties, Devon's interest in the major Paleogene discovery Kaskida (giving BP a 100% interest in the project), four producing assets and one non-producing asset. As part of the transaction, BP sold to Devon a 50% stake in its Kirby oil sands interests in Alberta, Canada for $500 million and Devon committed to fund an additional $150 million of capital costs on BP's behalf by issuing a promissory note to BP. In addition, the companies formed a 50:50 joint venture, operated by Devon, to pursue the development of the interest. On 16 August 2010, the group acquired Devon's 3.29% (after pre-emption exercised by some of the partners) interest in the BP-operated Azeri-Chirag-Gunashli (ACG) development in the Azerbaijan sector of the Caspian Sea for $1.1 billion, increasing BP's interest to 37.43%.

The business combination was accounted for using the acquisition method. Goodwill of $332 million was recognized on the 2010 part of the Devon transaction. As part of the Devon transaction, the gain on the disposal of the group's 50% interest in the Kirby oil sands in Alberta, Canada amounted to $633 million.

The final part of the Devon transaction, the acquisition of 100% of Devon's equity stake in a number of entities holding all Devon's assets in Brazil for consideration of $3.6 billion, completed in May 2011. Goodwill of $966 million was recognized in 2011 for this part of the transaction.

In addition to the Devon transaction, BP undertook a number of other minor business combinations in 2010, the most significant of which was the acquisition by BP's Alternative Energy business of Verenium Corporation's lignocellulosic biofuels business, for consideration of $98 million.

4. Non-current assets held for sale

As a result of the group's disposal programme, various assets, and associated liabilities, have been presented as held for sale in the group balance sheet at 31 December 2012. The carrying amount of the assets held for sale is $19,315 million, with associated liabilities of $846 million.

The majority of the transactions noted below are subject to post-closing adjustments, which may include adjustments for working capital and adjustments for profits attributable to the purchaser between the agreed effective date and the closing date of the transaction. Such post-closing adjustments may result in the final amounts received by BP from the purchasers differing from the disposal proceeds noted below. Non-current assets held for sale at 31 December 2012 included the following items:

Upstream

On 28 November 2012, BP announced that it had agreed to sell its interests in a number of central North Sea oil and gas fields to TAQA for $1,058 million plus future payments which, dependent on oil price and production, are currently expected to exceed $250 million after tax. The assets included in the sale are BP's interests in the BP-operated Maclure, Harding and Devenick fields and non-operated interests in the Brae complex of fields and the Braemar field. The sale is subject to third-party and regulatory approvals and is expected to complete in the second quarter of 2013.

Downstream

On 13 August 2012, BP announced that it had reached agreement to sell its Carson refinery in California and related assets in the region, including marketing and logistics assets, to Tesoro Corporation for $2.5 billion. The assets, and associated liabilities, of the refinery and related assets are classified as held for sale in the group balance sheet at 31 December 2012. Completion is subject to regulatory and other approvals, and the transaction is expected to close by the middle of 2013.

4. Non-current assets held for sale continued

On 1 February 2013, BP announced that it had completed the sale of its Texas City refinery and a portion of its retail and logistics network in the south-eastern US to Marathon Petroleum Corporation for $0.6 billion in relation to the fixed assets, $1.1 billion related to working capital, principally inventory, and a six-year earn-out arrangement, of up to $0.7 billion, based on future margins and refinery throughput. The consideration is subject to post-closing adjustments and will be fair-valued for accounting purposes. The assets, and associated liabilities, of the refinery and related retail and logistics network are classified as held for sale in the group balance sheet at 31 December 2012.

TNK-BP

On 22 October 2012, BP announced that it had signed heads of terms for a proposed transaction to sell its 50% share in TNK-BP to Rosneft. From this date, BP's investment in TNK-BP met the criteria to be classified as an asset held for sale. Consequently, BP ceased equity accounting for its share of TNK-BP's earnings from the date of the announcement. The TNK-BP segment result includes a dividend of $709 million paid by TNK-BP subsequent to the reclassification. BP continues to report its share of TNK-BP's production and reserves until the transaction closes.

On 22 November 2012, BP announced that it, Rosneft and Rosneftegaz – the Russian state-owned parent company of Rosneft – had signed definitive and binding sale and purchase agreements for the sale of BP's 50% interest in TNK-BP to Rosneft and for BP's investment in Rosneft. On completion, the overall effect of the transaction will be that BP will receive $11.6 billion in cash ($12.3 billion previously announced less the $0.7 billion dividend received by BP), subject to closing adjustments, and acquire an 18.5% stake in Rosneft for its stake in TNK-BP. Combined with BP's existing 1.25% shareholding, this will result in BP owning 19.75% of Rosneft. Completion of the transaction is subject to certain customary closing conditions, including governmental, regulatory and anti-trust approvals. Completion is expected to occur in the first half of 2013.

Impairment losses amounting to $2,594 million (2011 $398 million) have been recognized in relation to certain assets classified as held for sale as at 31 December 2012. See Note 5 for further information.

Non-current assets classified as held for sale are not depreciated. It is estimated that the benefit arising from the absence of depreciation for the assets noted above amounted to approximately $435 million (2011 $166 million). In addition, BP's share of profits of approximately $731 million were not recognized in 2012 as a result of the discontinuance of equity accounting.

Deposits of $632 million ($30 million at 31 December 2011) received in advance of completion of certain of these transactions have been classified as finance debt on the group balance sheet at 31 December 2012.

The major classes of assets and liabilities reclassified as held for sale as at 31 December are as follows:

		$ million
	2012	2011
Assets		
Property, plant and equipment	**3,663**	4,772
Goodwill	**89**	8
Intangible assets	**103**	20
Investments in jointly controlled entities	**108**	122
Investments in associates	**12,322**	38
Loans	**96**	–
Inventories	**2,377**	3,167
Cash	**–**	–
Other current assets	**557**	293
Assets classified as held for sale	**19,315**	8,420
Liabilities		
Trade and other payables	**158**	300
Provisions	**688**	98
Deferred tax liabilities	**–**	140
Liabilities directly associated with assets classified as held for sale	**846**	538

There were accumulated foreign exchange losses of $26 million recognized within other comprehensive income relating to the assets held for sale at 31 December 2012 (2011 nil).

2011

At 31 December 2011, within the Upstream segment, the Canadian natural gas liquids (NGL) business was classified as an asset held for sale and the sale completed in the first half of 2012. The investment in the Phu My 3 plant facility was classified as held for sale in the group balance sheet at 31 December 2011, for which a disposal deposit of $30 million had been received. This disposal did not complete during the year, the deposit was repaid and the assets are no longer classified as held for sale.

Within the Downstream segment, the Texas City refinery and related assets, and the southern part of the US West Coast fuels value chain, including the Carson refinery were classified as assets held for sale at 31 December 2011.

5. Disposals and impairment

The following amounts were recognized in the income statement in respect of disposals and impairments:

			$ million
	2012	2011	2010
Gains on sale of businesses and fixed assets			
Upstream	**6,504**	3,477	5,267
Downstream	**151**	317	999
Other businesses and corporate	**41**	336	117
	6,696	4,130	6,383

			$ million
	2012	2011	2010
Losses on sale of businesses and fixed assets			
Upstream	**109**	49	196
Downstream	**195**	52	119
Other businesses and corporate	**6**	3	6
	310	104	321
Impairment losses			
Upstream	**3,046**	1,443	1,259
Downstream	**2,892**	599	144
Other businesses and corporate	**320**	58	113
	6,258	2,100	1,516
Impairment reversals			
Upstream	**(289)**	(146)	–
Downstream	**(1)**	–	(141)
Other businesses and corporate	**(3)**	–	(7)
	(293)	(146)	(148)
Impairment and losses on sale of businesses and fixed assets	**6,275**	2,058	1,689

Disposals

As part of the response to the consequences of the Gulf of Mexico oil spill in 2010, the group announced plans to deliver up to $38 billion of disposal proceeds by the end of 2013. At 31 December 2012, BP had announced disposals of $38 billion, excluding the sale of our 50% investment in TNK-BP.

See Note 4 for further information relating to assets held for sale at 31 December 2012.

			$ million
	2012	2011	2010
Proceeds from disposals of fixed assets	**9,991**	3,500	7,492
Proceeds from disposals of businesses, net of cash disposed	**1,455**	(768)	9,462
	11,446	2,732	16,954
By business			
Upstream	**10,667**	1,080	14,392
Downstream	**485**	721	1,840
Other businesses and corporate	**294**	931	722
	11,446	2,732	16,954

Proceeds from disposals for 2012 include a deposit of $632 million received from a counterparty in respect of the disposal of interests in a number of central North Sea oil and gas fields. During 2012, a $30 million disposal deposit held at 31 December 2011 was returned as the sale did not complete. Proceeds from disposals for 2010 included deposits of $6,197 million received from counterparties in respect of disposal transactions in the Upstream segment not completed at 31 December 2010. This included a deposit of $3,530 million received in advance of the expected sale of our interest in Pan American Energy LLC. The repayment of the same amount following the termination of the sale agreement is included in proceeds from disposals for 2011. For further information on disposal transactions not yet completed see Note 4.

Deferred consideration relating to disposals of businesses and fixed assets at 31 December 2012 amounted to $24 million receivable within one year (2011 $117 million and 2010 $562 million) and $90 million receivable after one year (2011 $111 million and 2010 $271 million).

Upstream

In 2012, the major disposal transactions were the sale of our interests in the Marlin, Horn Mountain, Holstein, Ram Powell and Diana Hoover fields in the Gulf of Mexico to Plains Exploration and Production Company, the sale of our interests in the Hugoton and Jayhawk gas production and processing assets in Kansas, and our interest in the Jonah and Pinedale upstream operations in Wyoming, to LINN Energy, LLC, and the sale of our interests in our Canadian natural gas liquids (NGL) business to Plains Midstream Canada ULC. In addition, we sold a number of interests in the North Sea, including the disposal of our Southern Gas Assets to Perenco UK Ltd. All these transactions resulted in gains on disposal.

In 2011, the major disposal transactions were the sale of our interests in Colombia to Ecopetrol and Talisman, the sale of our upstream and midstream assets in Vietnam and our investments in equity-accounted entities in Venezuela to TNK-BP, and the sale of our assets in Pakistan to United Energy Group. In addition, we completed the disposal of half of the 3.29% interest in the Azeri-Chirag-Gunashli development in Azerbaijan to SOCAR and a number of interests in the Gulf of Mexico to Marubeni Group. All these transactions resulted in gains on disposal.

In 2010, the major transactions were the sale of Permian Basin assets in the US, upstream gas assets in Canada and exploration concessions in Egypt to Apache Corporation. In addition, we sold 50% of our interests in Kirby oil sands in Canada to Devon Energy as part of a business combination described in Note 3. All these transactions resulted in gains on disposal.

5. Disposals and impairment continued

Downstream

In 2012, gains on disposal resulted from the disposal of our interests in purified terephthalic acid production in Malaysia to Reliance Global Holdings Pte. Ltd., retail churn in the US and a number of other assets in the segment. Losses resulted from the ongoing costs associated with our US refinery divestments and the disposal of a number of assets in the segment portfolio.

In 2011, gains on disposal resulted from our disposal of the fuels marketing business in Namibia, Malawi, Zambia and Tanzania to Puma Energy, certain non-strategic pipelines and terminals in the US and other assets in the segment. Losses resulted from the disposal of a number of assets in the segment portfolio.

In 2010, gains resulted from our disposals of the French retail fuels and convenience business to Delek Europe, the fuels marketing business in Botswana to Puma Energy, certain non-strategic pipelines and terminals in the US, our interests in ethylene and polyethylene production in Malaysia to Petronas and our interest in a futures exchange. Losses resulted from the disposal of a number of assets in the segment portfolio.

Other businesses and corporate

In 2012, a gain arose on the additional cash consideration falling due on the contribution of assets in 2011 to the jointly controlled entity Flat Ridge 2 Wind Holdings LLC on meeting project milestones, whilst maintaining our 50% equity interests. In addition, disposal proceeds included a return of capital of $190 million in the jointly controlled entities Flat Ridge 2 Wind Holdings LLC and Mehoopany Wind Holdings LLC following the drawdown of project debt which did not change our percentage interest in either entity.

In 2011, we disposed of our aluminium business in the US which resulted in a gain. We also contributed assets in exchange for cash and 50% equity interests in the jointly controlled entities Mehoopany Wind Holdings LLC and Flat Ridge 2 Wind Holdings LLC.

In 2010, we disposed of our 35% interest in K-Power, a gas-fired power asset in South Korea, and contributed assets in exchange for a 50% equity interest in a jointly controlled entity, Cedar Creek II Holdings LLC and cash. In addition, there was a return of capital in the jointly controlled entities Fowler II Holdings LLC and Cedar Creek II Holdings LLC which did not change our percentage interest in either entity.

Summarized financial information relating to the sale of businesses is shown in the table below. Information relating to sales of fixed assets which are not related to businesses is excluded from the table.

			$ million
	2012	2011	2010
Non-current assets	**610**	2,085	2,319
Current assets	**570**	1,008	310
Non-current liabilities	**(263)**	(212)	(303)
Current liabilities	**(232)**	(611)	(124)
Total carrying amount of net assets disposed	**685**	2,270	2,202
Recycling of foreign exchange on disposal	**(15)**	8	(52)
Costs on disposal	**39**	17	18
	709	2,295	2,168
Profit (loss) on sale of businesses[a]	**675**	2,232	1,968
Total consideration	**1,384**	4,527	4,136
Consideration received (receivable)[b]	**(75)**	11	20
Proceeds from the sale of businesses related to completed transactions	**1,309**	4,538	4,156
Deposits received (repaid) related to assets classified as held for sale[c]	**146**	(3,530)	5,306
Disposals completed in relation to which deposits had been received in prior year	**–**	(1,776)	–
Proceeds from the sale of businesses[d]	**1,455**	(768)	9,462

[a] In 2011, a $278 million gain was not recognized in the income statement as it represented an unrealized gain on the sale of business assets in Vietnam to our associate TNK-BP.

[b] Consideration received from prior year business disposals or not yet received from current year disposals.

[c] 2010 included a deposit received in advance of $3,530 million in respect of the expected sale of our interest in Pan American Energy LLC; 2011 includes the repayment of the same amount following the termination of the sale agreement.

[d] Net of cash and cash equivalents disposed of $4 million (2011 $14 million and 2010 $55 million).

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 losses 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 2012, the rates used ranged from 12-14% (2011 12-14%). The rate applied in each country is reassessed each year. In certain circumstances 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.

Upstream

During 2012, the Upstream segment recognized impairment losses of $3,046 million. The main elements were a $1,082-million write-down to fair value less costs to sell based on recent market transactions of our interests in the Fayetteville and Woodford shale gas assets in the US, due to reserves revisions; a $999-million impairment loss relating to the decision to suspend the Liberty project in Alaska; a $706-million aggregate write-down of a number of assets, primarily in the Gulf of Mexico and North Sea, caused by increases in the decommissioning provision resulting from continued review of the expected decommissioning costs; a $144-million write-down of certain gas storage assets in Europe due to changes to the European gas market; and other impairment losses amounting to $116 million in total that were not individually significant. These impairment losses were partly offset by reversals of impairment of certain of our interests in the Gulf of Mexico amounting to $222 million, triggered by a decision to divest assets; and other reversals of impairment amounting to $67 million in total that were not individually significant.

5. Disposals and impairment continued

During 2011, the Upstream segment recognized impairment losses of $1,443 million. The main elements were a $555-million impairment loss relating to a number of our interests in the Gulf of Mexico, caused by an increase in the decommissioning provision as a result of further assessments of the regulations relating to idle infrastructure and a decrease in our assumption of the discount rate for provisions; the $393-million write-down of our interest in the Fayetteville shale gas asset in the US, triggered by a decrease in value by reference to a sale transaction by a partner of its interest in the same asset; and the $153-million write-down of our interest in the proposed Denali gas pipeline in Alaska, resulting from a decision not to proceed with the project. There were several other impairment losses amounting to $342 million in total that were not individually significant. These impairment losses were partly offset by reversals of impairment of certain of our interests in the Gulf of Mexico and Egypt amounting to $146 million in total, triggered by an increase in our assumption of long-term oil prices.

During 2010, the Upstream segment recognized impairment losses of $1,259 million. The main elements were the $501-million write-down of assets in the Gulf of Mexico, triggered by an increase in the decommissioning provision as a result of new regulations in the US relating to idle infrastructure; impairments of oil and gas properties in the Gulf of Mexico and onshore North America of $310 million and $80 million respectively, as a result of decisions to dispose of assets at a price lower than the assets' carrying values; a $341-million write-down of accumulated costs in Sakhalin, Russia, triggered by a change in the outlook on the future recoverability of the investment; and several other individually insignificant impairment losses amounting to $27 million in total.

Downstream

During 2012, the Downstream segment recognized impairment losses of $2,892 million, largely related to assets held for sale for which sales prices had been agreed, see Note 4 for further information. This impairment loss included $1,552 million relating to the Texas City refinery and associated assets and $1,042 million relating to the Carson refinery and associated assets.

During 2011, the Downstream segment recognized impairment losses of $599 million. Impairment losses of $398 million related to assets classified as held for sale. Other impairment losses were also recognized relating to retail churn in Europe and other minor asset disposals amounting to $201 million in total.

During 2010, the Downstream segment recognized impairment losses amounting to $144 million relating to retail churn in Europe and other minor asset disposals. These losses were largely offset by the reversal of a previously recognized impairment loss of $141 million relating to the investment in our jointly controlled entity China American Petrochemical Company resulting from a change in market conditions.

Other businesses and corporate

During 2012, 2011 and 2010, Other businesses and corporate recognized impairment losses totalling $318 million, $58 million and $113 million respectively related to various assets in the Alternative Energy business. The amount for 2012 includes $258 million in respect of the decision not to proceed with an investment in a biofuels production facility under development in the US.

6. Segmental analysis

The group's organizational structure reflects the various activities in which BP is engaged. In 2012, BP had three reportable segments: Upstream, Downstream and TNK-BP. BP's activities in low-carbon energy are managed through our Alternative Energy business, which is reported in Other businesses and corporate.

Upstream's activities include oil and natural gas exploration, field development and production; midstream transportation, storage and processing; and the marketing and trading of natural gas, including liquefied natural gas (LNG), together with power and natural gas liquids (NGLs). The segment is organized into three functional divisions – Exploration, Developments and Production – integrated through a Strategy and Integration organization.

Downstream's activities include the refining, manufacturing, marketing, transportation, and supply and trading of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers.

From 1 January 2012, the group's investment in TNK-BP is reported as a separate operating segment, rather than within the Upstream segment, reflecting the way in which the investment is managed. On 22 October 2012, BP announced that it had signed heads of terms for a proposed transaction to sell its 50% share in TNK-BP to Rosneft. Following this agreement, BP's investment in TNK-BP met the criteria to be classified as held for sale and the transaction is expected to complete in the first half of 2013. See Note 4 for further information.

Other businesses and corporate comprises the Alternative Energy business, Shipping, Treasury (which in the segmental analysis includes all of the group's cash, cash equivalents and associated interest income), and corporate activities worldwide. It also included the group's aluminium business until its disposal during 2011. 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.

In 2010, following the Gulf of Mexico incident, we established the Gulf Coast Restoration Organization (GCRO) and equipped it with dedicated resources and capabilities to manage all aspects of our response to the incident. This organization reports directly to the group chief executive and is overseen by a board committee, however it is not an operating segment.

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 or loss before interest and tax which reflects the replacement cost of supplies by excluding from profit or loss inventory holding gains and losses[a]. Replacement cost profit or loss for the group is not a recognized measure under IFRS.

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 by region are based on the location of the seller. The UK region includes the UK-based international activities of Downstream.

[a] Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies acquired during the period and the cost of sales calculated on the first-in first-out (FIFO) method after adjusting for 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 its historic cost of purchase, or manufacture, rather than its 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) for inventory on a FIFO basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen if an average cost of supplies was used for the period. For this purpose, the average cost of supplies during the period is principally calculated on a monthly basis by dividing the total cost of inventory acquired 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.

6. Segmental analysis continued

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
							2012
By business	Upstream	Downstream	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
Segment revenues							
Sales and other operating revenues	71,940	346,491	–	1,985	–	(44,836)	375,580
Less: sales and other operating revenues between businesses	(42,572)	(1,365)	–	(899)	–	44,836	–
Third party sales and other operating revenues	29,368	345,126	–	1,086	–	–	375,580
Equity-accounted earnings	1,054	446	2,986	(67)	–	–	4,419
Interest income	112	27	–	104	–	–	243
Segment results							
Replacement cost profit (loss) before interest and taxation	22,474	2,846	3,373	(2,795)	(4,995)	(576)	20,327
Inventory holding losses[a]	(104)	(487)	(3)	–	–	–	(594)
Profit (loss) before interest and taxation	22,370	2,359	3,370	(2,795)	(4,995)	(576)	19,733
Finance costs							(1,125)
Net finance income relating to pensions and other post-retirement benefits							201
Profit before taxation							18,809
Other income statement items							
Depreciation, depletion and amortization	10,309	1,769	–	403	–	–	12,481
Impairment losses	3,046	2,892	–	320	–	–	6,258
Impairment reversals	(289)	(1)	–	(3)	–	–	(293)
Fair value (gain) loss on embedded derivatives	(347)	–	–	–	–	–	(347)
Charges for provisions, net of write-back of unused provisions and derecognition of provisions, including change in discount rate	898	142	–	505	6,074	–	7,619
Segment assets							
Equity-accounted investments	11,084	6,567	–	1,071	–	–	18,722
Additions to non-current assets	21,935	5,045	–	1,419	–	–	28,399
Additions to other investments							33
Element of acquisitions not related to non-current assets							(72)
Additions to decommissioning asset							(4,018)
Capital expenditure and acquisitions	17,859	5,048	–	1,435	–	–	24,342

[a] See explanation of inventory holding gains and losses on page 203.

$ million

2011

By business	Upstream	Downstream	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
Segment revenues							
Sales and other operating revenues	75,475	344,116	–	2,957	–	(47,031)	375,517
Less: sales and other operating revenues between businesses	(44,766)	(1,396)	–	(869)	–	47,031	–
Third party sales and other operating revenues	30,709	342,720	–	2,088	–	–	375,517
Equity-accounted earnings	1,281	787	4,185	(33)	–	–	6,220
Interest income	(4)	25	–	146	–	–	167
Segment results							
Replacement cost profit (loss) before interest and taxation	26,366	5,474	4,134	(2,478)	3,800	(113)	37,183
Inventory holding gains[a]	81	2,487	51	15	–	–	2,634
Profit (loss) before interest and taxation	26,447	7,961	4,185	(2,463)	3,800	(113)	39,817
Finance costs							(1,246)
Net finance income relating to pensions and other post-retirement benefits							263
Profit before taxation							38,834
Other income statement items							
Depreciation, depletion and amortization	8,693	2,117	–	325	–	–	11,135
Impairment losses	1,443	599	–	58	–	–	2,100
Impairment reversals	(146)	–	–	–	–	–	(146)
Fair value (gain) loss on embedded derivatives	(191)	–	–	123	–	–	(68)
Charges for provisions, net of write-back of unused provisions, including change in discount rate	213	371	–	942	5,200	–	6,726
Segment assets							
Equity-accounted investments	11,041	6,731	10,013	1,024	–	–	28,809
Additions to non-current assets	34,527	4,128	–	1,864	–	–	40,519
Additions to other investments							25
Element of acquisitions not related to non-current assets							(1,089)
Additions to decommissioning asset							(7,937)
Capital expenditure and acquisitions	25,535	4,130	–	1,853	–	–	31,518

[a] See explanation of inventory holding gains and losses on page 203.

6. Segmental analysis continued

							$ million
							2010
By business	Upstream	Downstream	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
Segment revenues							
Sales and other operating revenues	66,266	266,751	–	3,328	–	(39,238)	297,107
Less: sales and other operating revenues between businesses	(37,049)	(1,358)	–	(831)	–	39,238	–
Third party sales and other operating revenues	29,217	265,393	–	2,497	–	–	297,107
Equity-accounted earnings	1,362	755	2,617	23	–	–	4,757
Interest income	83	46	–	109	–	–	238
Segment results							
Replacement cost profit (loss) before interest and taxation	28,269	5,555	2,617	(1,516)	(40,858)	447	(5,486)
Inventory holding gains[a]	84	1,684	–	16	–	–	1,784
Profit (loss) before interest and taxation	28,353	7,239	2,617	(1,500)	(40,858)	447	(3,702)
Finance costs							(1,170)
Net finance income relating to pensions and other post-retirement benefits							47
Loss before taxation							(4,825)
Other income statement items							
Depreciation, depletion and amortization	8,616	2,258	–	290	–	–	11,164
Impairment losses	1,259	144	–	113	–	–	1,516
Impairment reversals	–	(141)	–	(7)	–	–	(148)
Fair value loss on embedded derivatives	309	–	–	–	–	–	309
Charges for provisions, net of write-back of unused provisions, including change in discount rate	303	275	–	206	30,266	–	31,050
Segment assets							
Equity-accounted investments	10,384	7,043	9,995	840	–	–	28,262
Additions to non-current assets	20,113	4,030	–	1,226	–	–	25,369
Additions to other investments							20
Element of acquisitions not related to non-current assets							(401)
Additions to decommissioning asset							(1,972)
Capital expenditure and acquisitions	17,753	4,029	–	1,234	–	–	23,016

[a] See explanation of inventory holding gains and losses on page 203.

6. Segmental analysis continued

			$ million
			2012
By geographical area	**US**	**Non-US**	**Total**
Revenues			
Third party sales and other operating revenues[a]	**130,940**	**244,640**	**375,580**
Results			
Replacement cost profit before interest and taxation	**180**	**20,147**	**20,327**
Non-current assets			
Other non-current assets[b,c]	**68,295**	**107,586**	**175,881**
Other investments			**2,702**
Loans			**695**
Trade and other receivables			**4,754**
Derivative financial instruments			**4,294**
Deferred tax assets			**874**
Defined benefit pension plan surpluses			**12**
Total non-current assets			**189,212**
Capital expenditure and acquisitions	**10,410**	**13,932**	**24,342**

[a] Non-US region includes UK $75,364 million.

[b] Non-US region includes UK $17,545 million.

[c] Excluding financial instruments, deferred tax assets and defined benefit pension plan surpluses.

			$ million
			2011
By geographical area	US	Non-US	Total
Revenues			
Third party sales and other operating revenues[a]	131,488	244,029	375,517
Results			
Replacement cost profit before interest and taxation	10,202	26,981	37,183
Non-current assets			
Other non-current assets[b,c]	68,191	113,773	181,964
Other investments			2,633
Loans			884
Trade and other receivables			4,337
Derivative financial instruments			5,038
Deferred tax assets			611
Defined benefit pension plan surpluses			17
Total non-current assets			195,484
Capital expenditure and acquisitions	8,830	22,688	31,518

[a] Non-US region includes UK $75,816 million.

[b] Non-US region includes UK $18,363 million.

[c] Excluding financial instruments, deferred tax assets and defined benefit pension plan surpluses.

			$ million
			2010
By geographical area	US	Non-US	Total
Revenues			
Third party sales and other operating revenues[a]	101,768	195,339	297,107
Results			
Replacement cost profit (loss) before interest and taxation	(30,087)	24,601	(5,486)
Non-current assets			
Other non-current assets[b,c]	67,000	95,255	162,255
Other investments			1,689
Loans			894
Trade and other receivables			6,298
Derivative financial instruments			4,210
Deferred tax assets			528
Defined benefit pension plan surpluses			2,176
Total non-current assets			178,050
Capital expenditure and acquisitions	10,370	12,646	23,016

[a] Non-US region includes UK $62,794 million.

[b] Non-US region includes UK $16,650 million.

[c] Excluding financial instruments, deferred tax assets and defined benefit pension plan surpluses.

7. Interest and other income

			$ million
	2012	2011	2010
Interest income			
Interest income from available-for-sale financial assets[a]	**14**	21	23
Interest income from loans and receivables[a]	**62**	101	88
Interest from loans to equity-accounted entities	**36**	32	36
Other interest	**131**	13	91
	243	167	238
Other income			
Dividend income from available-for-sale financial assets[a]	**51**	29	37
Other income[ab]	**1,296**	400	406
	1,347	429	443
	1,590	596	681

[a] Total interest and other income related to financial instruments amounted to $197 million (2011 $172 million and 2010 $206 million).

[b] 2012 includes $709 million of dividends received from TNK-BP. See Note 4 for further information.

8. Production and similar taxes

			$ million
	2012	2011	2010
US	**1,472**	1,854	1,093
Non-US	**6,686**	6,426	4,151
	8,158	8,280	5,244

9. Depreciation, depletion and amortization

			$ million
By business	**2012**	2011	2010
Upstream			
US	**3,437**	3,201	3,751
Non-US	**6,872**	5,492	4,865
	10,309	8,693	8,616
Downstream			
US	**562**	840	955
Non-US[a]	**1,207**	1,277	1,303
	1,769	2,117	2,258
Other businesses and corporate			
US	**213**	151	140
Non-US	**190**	174	150
	403	325	290
By geographical area			
US	**4,212**	4,192	4,846
Non-US	**8,269**	6,943	6,318
	12,481	11,135	11,164

[a] Non-US area includes the UK-based international activities of Downstream.

10. Impairment review of goodwill

		$ million
Goodwill at 31 December	**2012**	2011
Upstream	**7,533**	7,931
Downstream	**4,168**	4,014
Other businesses and corporate	**160**	155
	11,861	12,100

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 Upstream, goodwill is held at the segment level. For Downstream, goodwill has been allocated to the Rhine fuels value chain (FVC), Lubricants and Other.

In assessing whether goodwill has been impaired, the carrying amount of the cash-generating unit (CGU) or groups of CGUs (including goodwill) is compared with the recoverable amount of the CGU or groups of CGUs. 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.

10. Impairment review of goodwill continued

The group calculates 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. Discount rates of 12% and 14% have been used for goodwill impairment calculations performed in 2012 (2011 12% and 14%).

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.

Upstream

		$ million
	2012	2011
Goodwill	**7,533**	7,931
Excess of recoverable amount over carrying amount	**26,614**	49,247

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 BP'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. 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 2012 review for impairment was carried out during the fourth quarter.

The table above shows the carrying amount of the goodwill for the segment and the excess of the recoverable amount over the carrying amount (the headroom). Consistent with prior periods, midstream and intangible oil and gas assets were excluded from the headroom calculation.

The Brent oil price assumption used in the impairment review of goodwill is shown in the table below.

						2012
	2013	**2014**	**2015**	**2016**	**2017**	**2018 and thereafter**
Brent oil price ($/bbl)	**105**	**100**	**96**	**93**	**91**	**90**

						2011
	2012	2013	2014	2015	2016	2017 and thereafter
Brent oil price ($/bbl)	106	101	97	94	92	90

Key assumptions for oil and gas prices for the first five years were derived from forward price curves in the fourth quarter. Prices in 2018 and beyond were determined using long-term views of global supply and demand, building upon past experience of the industry and using information from external sources. These prices were adjusted to arrive at appropriate consistent price assumptions for different qualities of oil and gas or, where appropriate, contracted oil and gas prices were applied.

The key assumptions required for the value-in-use estimation are the oil and natural gas prices, production volumes and the discount rate. The sensitivity of the headroom to changes in the key assumptions was estimated. A change in any one variable will impact multiple other inputs to the calculation such that the relationship between any variables will not be linear. In order to simplify the sensitivity calculations they were performed assuming a change to the variable being tested only. A detailed calculation on any given change in assumptions may therefore produce a different result.

It was estimated that if the oil price assumption for all future years was around 12% lower than the current assumption for 2018 and beyond, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment. It was estimated that no reasonably possible change in the long-term price of natural gas would cause the headroom 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. The average production for the purposes of goodwill impairment testing over the next 15 years is 563mmboe per year. In 2012, it was estimated that if this production were to be reduced by around 7% for the whole of this period then this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment.

Management believes that currently there is no reasonably possible change in discount rate that would cause the carrying amount to exceed the recoverable amount.

10. Impairment review of goodwill continued

Downstream

$ million

	2012				2011			
	Rhine FVC	**Lubricants**	**Other**	**Total**	Rhine FVC	Lubricants	Other	Total
Goodwill	**627**	**3,441**	**100**	**4,168**	618	3,284	112	4,014
Excess of recoverable amount over carrying amount	**2,178**	**n/a**	**n/a**	**n/a**	2,264	n/a	n/a	n/a

Cash flows for each cash-generating unit are derived from the business segment plans, which cover a period of two to five years. To determine the value in use for each of the cash-generating units, cash flows for a period of 10 years are discounted and aggregated with a terminal value.

Rhine FVC

The key assumptions to which the calculation of value in use for the Rhine FVC is most sensitive are refinery gross margins, throughput volumes and discount rate. Gross margin assumptions used in the Rhine FVC plan are consistent with those used to develop the regional Refining Marker Margin (RMM). The average values assigned to the regional RMM and refinery throughput volume over the plan period are $12.30 per barrel and 246mmbbl per year (2011 $11.35 per barrel and 257mmbbl per year). These values reflect past experience and are consistent with external sources. Cash flows beyond the five-year plan period are extrapolated using a nominal 4% growth rate (2011 cash flows beyond the five-year plan period were extrapolated using a nominal 4% growth rate).

	2012
Sensitivity analysis	
Sensitivity of value in use to a change in refinery margins of $1 per barrel ($ billion)	**1.5**
Adverse change in refinery margins to reduce recoverable amount to carrying amount ($ per barrel)	**1.4**
Sensitivity of value in use to a 5% change in production volume ($ billion)	**0.9**
Adverse change in throughput volume to reduce recoverable amount to carrying amount (million barrels per year)	**30**
Sensitivity of value in use to a change in the discount rate of 1% ($ billion)	**0.6**
Discount rate to reduce recoverable amount to carrying amount	**16%**

Lubricants

As permitted by IAS 36, the detailed calculations of the Lubricants unit's recoverable amount performed in the most recent detailed calculation in 2009 were used for the 2012 impairment test as the criteria in that standard were considered satisfied: the headroom was substantial in 2009; there have been no significant changes in the assets and liabilities; and the likelihood that the recoverable amount would be less than the carrying amount at the time was remote.

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 changes in any of these key assumptions would cause the unit's carrying amount to exceed its recoverable amount. Cash flows beyond the two-year plan period were extrapolated using a nominal 3% growth rate.

11. Distribution and administration expenses

$ million

	2012	2011	2010
Distribution	**11,561**	12,416	11,393
Administration	**1,796**	1,542	1,162
	13,357	13,958	12,555

12. Currency exchange gains and losses

$ million

	2012	2011	2010
Currency exchange losses (gains) charged (credited) to the income statement[a]	**113**	(70)	218

[a] Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.

13. Research and development

$ million

	2012	2011	2010
Expenditure on research and development	**674**	636	780

14. Operating leases

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
	2012	2011	2010
Minimum lease payments	**5,255**	4,866	5,371
Contingent rentals	**(79)**	(97)	(60)
Sub-lease rentals	**(228)**	(153)	(121)
	4,948	4,616	5,190

The future minimum lease payments at 31 December 2012, before deducting related rental income from operating sub-leases of $271 million (2011 $566 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	**2012**	2011
Payable within		
1 year	**4,531**	4,182
2 to 5 years	**9,733**	8,346
Thereafter	**4,195**	3,544
	18,459	16,072

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 Upstream segment. At 31 December 2012, the future minimum lease payments relating to drilling rigs amounted to $8,527 million (2011 $6,292 million).

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, and some of the group's operating leases contain escalation clauses.

15. 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 Upstream segment.

			$ million
	2012	2011	2010
Exploration and evaluation costs			
Exploration expenditure written off	**745**	1,024	375
Other exploration costs	**730**	496	468
Exploration expense for the year	**1,475**	1,520	843
Intangible assets – exploration and appraisal expenditure	**22,849**	19,887	13,126
Liabilities	**287**	306	157
Net assets	**22,562**	19,581	12,969
Capital expenditure	**5,137**	8,911	6,422
Net cash used in operating activities	**729**	496	468
Net cash used in investing activities	**4,971**	8,556	6,428

16. Auditor's remuneration

			$ million
Fees – Ernst & Young	**2012**	2011	2010
The audit of the company annual accounts[a]	**24**	24	25
The audit of accounts of any subsidiaries of the company	**9**	11	12
Total audit	**33**	35	37
Audit-related assurance services[b]	**13**	12	14
Total audit and audit-related assurance services	**46**	47	51
Taxation compliance services	**2**	1	1
Taxation advisory services	**2**	1	1
Services relating to corporate finance transactions	**2**	4	–
Other assurance services	**1**	1	1
Total non-audit or non-audit-related assurance services	**7**	7	3
Services relating to BP pension plans[c]	**1**	1	1
	54	55	55

[a] Fees in respect of the audit of the accounts of BP p.l.c. including the group's consolidated financial statements.

[b] Includes interim reviews and reporting on internal financial controls and non-statutory audit services.

[c] The pension plan services include tax compliance services of $50,000 (2011 $108,000 and 2010 $300,000).

2012 includes $2 million of additional fees for 2011, and 2011 includes $1 million of additional fees for 2010. Auditor's 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 (2011 $55 million and 2010 $55 million) is required to be presented as follows: audit $33 million (2011 $35 million and 2010 $37 million); other audit-related services $13 million (2011 $12 million and 2010 $14 million); tax $4 million (2011 $2 million and 2010 $2 million); and all other fees $4 million (2011 $6 million and 2010 $2 million).

17. Finance costs

			$ million
	2012	2011	2010
Interest payable	**1,220**	1,135	955
Capitalized at 2.25% (2011 2.63% and 2010 2.75%)[a]	**(378)**	(347)	(254)
Unwinding of discount on provisions[b]	**140**	243	234
Unwinding of discount on other payables[b]	**143**	215	235
	1,125	1,246	1,170

[a] Tax relief on capitalized interest is $93 million (2011 $107 million and 2010 $71 million).

[b] Unwinding of discount on provisions relating to the Gulf of Mexico oil spill was $7 million (2011 $6 million and 2010 $4 million) and unwinding of discount on other payables relating to the Gulf of Mexico oil spill was $12 million (2011 $52 million and 2010 $73 million). See Note 2 for further information on the financial impacts of the Gulf of Mexico oil spill.

18. Taxation

Tax on profit

			$ million
	2012	2011	2010
Current tax			
Charge for the year	**6,632**	7,477	6,766
Adjustment in respect of prior years	**252**	111	(74)
	6,884	7,588	6,692
Deferred tax			
Origination and reversal of temporary differences in the current year	**212**	5,664	(8,157)
Adjustment in respect of prior years	**(103)**	(515)	(36)
	109	5,149	(8,193)
Tax charge (credit) on profit (loss)	**6,993**	12,737	(1,501)

Tax included in other comprehensive income[a]

			$ million
	2012	2011	2010
Current tax	**2**	(10)	(107)
Deferred tax	**(448)**	(1,649)	244
	(446)	(1,659)	137

[a] See Note 39 for further information.

18. Taxation continued

Tax included directly in equity

			$ million
	2012	2011	2010
Current tax	**(10)**	–	(37)
Deferred tax	**4**	(7)	64
	(6)	(7)	27

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 or loss before taxation. With effect from 1 April 2012 the UK statutory corporation tax rate reduced from 26% to 24% on profits arising from activities outside the North Sea.

For 2010, the items presented in the reconciliation are distorted as a result of the overall tax credit for the year and the loss before taxation. In order to provide a more meaningful analysis of the effective tax rate for 2010, the table also presents separate reconciliations for the group excluding the impacts of the Gulf of Mexico oil spill, and for the impacts of the Gulf of Mexico oil spill in isolation.

					$ million
	2012	2011	2010 excluding impacts of Gulf of Mexico oil spill	2010 impacts of Gulf of Mexico oil spill	2010
Profit (loss) before taxation	**18,809**	38,834	36,110	(40,935)	(4,825)
Tax charge (credit) on profit (loss)	**6,993**	12,737	11,393	(12,894)	(1,501)
Effective tax rate	**37%**	33%	32%	31%	31%

					% of profit or loss before taxation
UK statutory corporation tax rate	**24**	26	28	28	28
Increase (decrease) resulting from					
UK supplementary and overseas taxes at higher or lower rates[a]	**11**	14	9	7	(4)
Tax reported in equity-accounted entities	**(5)**	(3)	(3)	–	23
Adjustments in respect of prior years	**1**	(1)	–	–	2
Movements in losses not recognized	**–**	–	–	–	1
Tax incentives for investment	**(2)**	(1)	(1)	–	9
Gulf of Mexico oil spill non-deductible costs	**8**	–	–	(4)	(30)
Permanent differences relating to disposals	**–**	(2)	(1)	–	5
Other	**–**	–	–	–	(3)
Effective tax rate	**37**	33	32	31	31

[a] For 2012, the jurisdictions which contributed significantly to this item were Angola, with an applicable statutory tax rate of 50%, the UK, with an applicable statutory tax rate of 62% for North Sea activities, and Trinidad & Tobago, with an applicable statutory tax rate of 55%.

Deferred tax

					$ million
	Income statement			Balance sheet	
	2012	2011[a]	2010[a]	**2012**	2011[a]
Deferred tax liability					
Depreciation	**(121)**	4,738	1,304	**31,839**	32,119
Pension plan surpluses	**–**	–	38	**–**	–
Other taxable temporary differences	**(2,240)**	149	1,178	**3,681**	5,704
	(2,361)	4,887	2,520	**35,520**	37,823
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**160**	388	179	**(3,389)**	(2,872)
Decommissioning, environmental and other provisions	**1,872**	(1,443)	(8,210)	**(12,705)**	(14,743)
Derivative financial instruments	**(7)**	24	(56)	**(281)**	(274)
Tax credits	**1,802**	(401)	(1,088)	**(714)**	(2,549)
Loss carry forward	**(912)**	(218)	24	**(2,209)**	(1,295)
Other deductible temporary differences	**(445)**	1,912	(1,562)	**(2,032)**	(1,623)
	2,470	262	(10,713)	**(21,330)**	(23,356)
Net deferred tax charge (credit) and net deferred tax liability	**109**	5,149	(8,193)	**14,190**	14,467
Of which – deferred tax liabilities				**15,064**	15,078
– deferred tax assets				**874**	611

[a] Certain comparative amounts shown in the analysis of deferred tax by category of temporary difference have been reclassified. There is no change to the tax amounts reported in the income statement, balance sheet or cash flow statement.

18. Taxation continued

Analysis of movements during the year in the net deferred tax liability	$ million 2012	2011
At 1 January	**14,467**	10,380
Exchange adjustments	**(33)**	55
Charge for the year on profit	**109**	5,149
Credit for the year in other comprehensive income	**(448)**	(1,649)
Charge (credit) for the year in equity	**4**	(7)
Acquisitions	**11**	692
Reclassified as assets/liabilities held for sale	**48**	(140)
Deletions	**32**	(13)
At 31 December	**14,190**	14,467

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 2012, the group had approximately $6.8 billion (2011 $4.6 billion) of carry-forward tax losses that would be available to offset against future taxable profit. A deferred tax asset has been recognized in respect of $6.0 billion of these losses (2011 $3.8 billion). No deferred tax asset has been recognized in respect of $0.8 billion of losses (2011 $0.8 billion). In 2012 no current tax benefit arose relating to losses utilized on which a deferred tax asset had not previously been recognized (2011 $0.1 billion). Substantially all the tax losses have no fixed expiry date.

At 31 December 2012, the group had approximately $19.0 billion of unused tax credits, predominantly in the UK and US (2011 $18.2 billion). At 31 December 2012, a deferred tax asset of $0.7 billion has been recognized in respect of unused tax credits (2011 $2.5 billion). No deferred tax asset has been recognized in respect of $18.3 billion of tax credits (2011 $15.7 billion). In 2012 a current tax benefit of $0.4 billion arose relating to tax credits utilized on which a deferred tax asset had not previously been recognized (2011 $0.1 billion). Also in 2012, a deferred tax benefit of $0.1 billion arose relating to the recognition of previously unrecognized tax credits (2011 nil). The UK tax credits, arising in overseas branches of UK entities, with no associated deferred tax asset, amount to $16.0 billion (2011 $13.0 billion) and have no fixed expiry date. These credits arise in branches predominantly based in high tax rate jurisdictions so are unlikely to have value in the future as UK taxes on these overseas branches are largely mitigated by the double tax relief on the overseas tax. The US tax credits with no associated deferred tax asset, amounting to $2.3 billion (2011 $2.7 billion), expire 10 years after generation and will all expire in the period 2014-2021.

The group had other unrecognized deferred tax assets at 31 December 2012 of $1.8 billion (2011 $1.1 billion), of which $1.3 billion arose in the UK (2011 $0.9 billion), which have not been recognized due to uncertainty over future recovery.

The group recognized significant costs in 2010 in relation to the Gulf of Mexico oil spill and in 2011 recognized certain recoveries relating to the incident as well as further costs. In 2012, the group has recognized further costs, including costs relating to the settlement of all criminal and securities claims with the US government which are not tax deductible. Tax has been calculated on the expenditures that are expected to qualify for tax relief, and on the recoveries, at the US statutory tax rate. A deferred tax asset has been recognized in respect of provisions for future expenditure that are expected to qualify for tax relief, included under the heading decommissioning, environmental and other provisions in the table above.

The other major components of temporary differences at the end of 2012 relate to tax depreciation, provisions, US inventory holding gains (classified as other taxable temporary differences) and pension and other post-retirement benefit plan deficits.

During 2012, our method of accounting, for tax purposes, for oil and gas inventory in the US has changed from the last-in first-out ("LIFO") basis to the first-in first-out ("FIFO") basis. This has accelerated the taxation of inventory holding gains and reduced the taxable temporary difference in respect of this item.

At 31 December 2012, the group had $0.5 billion (2011 $0.1 billion) of taxable temporary differences associated with investments in subsidiaries and equity-accounted entities for which deferred tax liabilities have not been recognized on the basis that the group is able to control the timing of the reversal of the temporary differences and it is not probable that the temporary differences will reverse in the foreseeable future.

In 2012, legislation to restrict relief for UK decommissioning expenditure in the North Sea from 62% to 50% was enacted and increased the deferred tax charge in the income statement by $289 million, of which $256 million relates to the revaluation of the deferred tax balance at 1 January 2012. In 2011, the enactment of a 12% increase in the UK supplementary charge on oil and gas production activities in the North Sea raised the overall corporation tax rate applicable to North Sea activities to 62%. This rate change increased the deferred tax charge in the 2011 income statement by $713 million, of which $683 million related to the revaluation of the deferred tax balance at 1 January 2011.

Also in 2012, the enactment of a further 2% reduction in the rate of UK corporation tax to 23% with effect from 1 April 2013 on profits arising from activities outside the North Sea reduced the deferred tax charge in the income statement by $165 million. In 2011, the enactment of a 2% reduction in the rate of UK corporation tax to 25% with effect from 1 April 2011 similarly reduced the deferred tax charge in the income statement by $120 million.

19. Dividends

The quarterly dividend expected to be paid on 28 March 2013 in respect of the fourth quarter 2012 is 9 cents per ordinary share ($0.54 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 18 March 2013. A scrip dividend alternative is available, allowing shareholders to elect to receive their dividend in the form of new ordinary shares and ADS holders in the form of new ADSs.

	Pence per share			Cents per share			$ million		
	2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Dividends announced and paid in cash									
Preference shares							**2**	2	2
Ordinary shares									
March	**5.096**	4.3372	8.679	**8**	7	14	**1,211**	808	2,625
June	**5.150**	4.2809	–	**8**	7	–	**1,448**	794	–
September	**5.017**	4.3160	–	**8**	7	–	**1,417**	1,224	–
December	**5.589**	4.4694	–	**9**	7	–	**1,216**	1,244	–
	20.852	17.4035	8.679	**33**	28	14	**5,294**	4,072	2,627
Dividend announced, payable in March 2013				**9**			**1,724**		

19. Dividends continued

The details of the scrip dividends issued are shown in the table below.

	2012	2011	2010
Number of shares issued (thousand)	**138,406**	165,601	–
Value of shares issued ($ million)	**982**	1,219	–

The financial statements for the year ended 31 December 2012 do not reflect the dividend announced on 5 February 2013 and expected to be paid in March 2013; this will be treated as an appropriation of profit in the year ended 31 December 2013.

20. Earnings per ordinary share

			Cents per share
	2012	2011	2010
Basic earnings per share	**60.86**	135.93	(19.81)
Diluted earnings per share	**60.45**	134.29	(19.81)

Basic earnings per ordinary share amounts are calculated by dividing the profit or loss 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-based payment 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. If the inclusion of potentially issuable shares would decrease the loss per share, the potentially issuable shares are excluded from the diluted earnings per share calculation.

			$ million
	2012	2011	2010
Profit (loss) attributable to BP shareholders	**11,582**	25,700	(3,719)
Less: dividend requirements on preference shares	**2**	2	2
Profit (loss) for the year attributable to BP ordinary shareholders	**11,580**	25,698	(3,721)

			Shares thousand
	2012	2011	2010
Basic weighted average number of ordinary shares	**19,027,929**	18,904,812	18,785,912
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**129,959**	231,388	211,895
	19,157,888	19,136,200	18,997,807

The number of ordinary shares outstanding at 31 December 2012, excluding treasury shares and the shares held by the ESOPs, and including certain shares that will be issuable in the future under employee share-based payment plans was 19,119,756,993. Between 31 December 2012 and 19 February 2013, the latest practicable date before the completion of these financial statements, there was a net increase of 46,285,758 in the number of ordinary shares outstanding as a result of share issues in relation to employee share-based payment plans. The number of potential ordinary shares issuable in relation to employee share-based payment plans was 112,118,647 at 31 December 2012. There has been a net decrease of 42,238,872 in the number of potential ordinary shares between 31 December 2012 and 19 February 2013.

21. 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 2012	**3,099**	**2,846**	**175,874**	**35,709**	**3,095**	**12,753**	**8,611**	**241,987**
Exchange adjustments	**73**	**12**	**–**	**229**	**29**	**8**	**272**	**623**
Additions	**120**	**387**	**15,709**	**4,248**	**312**	**902**	**533**	**22,211**
Acquisitions	**–**	**–**	**44**	**2**	**–**	**15**	**–**	**61**
Transfers	**–**	**–**	**1,306**	**–**	**–**	**–**	**–**	**1,306**
Reclassified as assets held for sale	**–**	**–**	**(19,410)**	**(143)**	**–**	**(172)**	**(2)**	**(19,727)**
Deletions	**(96)**	**(532)**	**(3,460)**	**(758)**	**(135)**	**(70)**	**(355)**	**(5,406)**
At 31 December 2012	**3,196**	**2,713**	**170,063**	**39,287**	**3,301**	**13,436**	**9,059**	**241,055**
Depreciation								
At 1 January 2012	**510**	**1,372**	**91,994**	**14,266**	**1,911**	**8,149**	**4,571**	**122,773**
Exchange adjustments	**8**	**12**	**–**	**165**	**24**	**6**	**151**	**366**
Charge for the year	**33**	**122**	**9,658**	**1,242**	**286**	**320**	**504**	**12,165**
Impairment losses	**8**	**–**	**2,765**	**493**	**–**	**70**	**7**	**3,343**
Impairment reversals	**–**	**–**	**(221)**	**–**	**–**	**–**	**(1)**	**(222)**
Reclassified as assets held for sale	**–**	**–**	**(13,774)**	**(36)**	**–**	**(126)**	**(2)**	**(13,938)**
Deletions	**(46)**	**(524)**	**(2,457)**	**(394)**	**(134)**	**(10)**	**(315)**	**(3,880)**
At 31 December 2012	**513**	**982**	**87,965**	**15,736**	**2,087**	**8,409**	**4,915**	**120,607**
Net book amount at 31 December 2012	**2,683**	**1,731**	**82,098**	**23,551**	**1,214**	**5,027**	**4,144**	**120,448**
Cost								
At 1 January 2011	3,560	2,835	160,184	42,827	2,965	12,216	9,652	234,239
Exchange adjustments	(73)	(73)	–	(294)	(35)	(12)	(225)	(712)
Additions	39	46	18,515	3,782	370	655	512	23,919
Acquisitions	62	134	2,100	567	4	–	–	2,867
Transfers	–	–	1,013	–	–	–	–	1,013
Reclassified as assets held for sale	(325)	–	(832)	(9,931)	–	–	–	(11,088)
Deletions	(164)	(96)	(5,106)	(1,242)	(209)	(106)	(1,328)	(8,251)
At 31 December 2011	3,099	2,846	175,874	35,709	3,095	12,753	8,611	241,987
Depreciation								
At 1 January 2011	572	1,384	88,047	19,183	1,876	7,940	5,074	124,076
Exchange adjustments	(10)	(36)	–	(108)	(34)	(6)	(113)	(307)
Charge for the year	36	111	8,116	1,411	278	252	567	10,771
Impairment losses	133	4	1,239	245	–	42	46	1,709
Impairment reversals	–	–	(146)	–	–	–	–	(146)
Reclassified as assets held for sale	(115)	–	(680)	(5,761)	–	–	–	(6,556)
Deletions	(106)	(91)	(4,582)	(704)	(209)	(79)	(1,003)	(6,774)
At 31 December 2011	510	1,372	91,994	14,266	1,911	8,149	4,571	122,773
Net book amount at 31 December 2011	2,589	1,474	83,880	21,443	1,184	4,604	4,040	119,214
Net book amount at 1 January 2011	2,988	1,451	72,137	23,644	1,089	4,276	4,578	110,163
Assets held under finance leases at net book amount included above								
At 31 December 2012	**–**	**9**	**157**	**254**	**–**	**9**	**–**	**429**
At 31 December 2011	–	10	213	326	–	7	18	574
Assets under construction included above								
At 31 December 2012								**27,308**
At 31 December 2011								26,443

22. Goodwill

$ million

	2012	2011
Cost		
At 1 January	**13,703**	10,177
Exchange adjustments	**160**	(26)
Acquisitions	**25**	3,602
Reclassified as assets held for sale	**(1,327)**	(50)
Deletions	**(95)**	–
At 31 December	**12,466**	13,703
Impairment losses		
At 1 January	**(1,603)**	(1,579)
Impairment losses for the year	**–**	(66)
Reclassified as assets held for sale	**977**	42
Deletions	**21**	–
At 31 December	**(605)**	(1,603)
Net book amount at 31 December	**11,861**	12,100
Net book amount at 1 January	**12,100**	8,598

23. Intangible assets

$ million

	2012			2011		
	Exploration and appraisal expenditure	**Other intangibles**	**Total**	Exploration and appraisal expenditure	Other intangibles	Total
Cost						
At 1 January	**20,670**	**3,474**	**24,144**	13,476	3,403	16,879
Exchange adjustments	**–**	**49**	**49**	–	(21)	(21)
Acquisitions	**(68)**	**80**	**12**	5,563	176	5,739
Additions	**5,205**	**341**	**5,546**	3,348	352	3,700
Transfers	**(1,306)**	**–**	**(1,306)**	(1,013)	–	(1,013)
Reclassified as assets held for sale	**(67)**	**(26)**	**(93)**	–	(66)	(66)
Deletions	**(508)**	**(208)**	**(716)**	(704)	(370)	(1,074)
At 31 December	**23,926**	**3,710**	**27,636**	20,670	3,474	24,144
Amortization						
At 1 January	**783**	**2,259**	**3,042**	350	2,231	2,581
Exchange adjustments	**–**	**24**	**24**	–	(11)	(11)
Charge for the year	**745**	**316**	**1,061**	1,024	364	1,388
Impairment losses	**–**	**126**	**126**	7	79	86
Impairment reversals	**(42)**	**–**	**(42)**	–	–	–
Reclassified as assets held for sale	**–**	**(21)**	**(21)**	–	(46)	(46)
Deletions	**(409)**	**(186)**	**(595)**	(598)	(358)	(956)
At 31 December	**1,077**	**2,518**	**3,595**	783	2,259	3,042
Net book amount at 31 December	**22,849**	**1,192**	**24,041**	19,887	1,215	21,102
Net book amount at 1 January	**19,887**	**1,215**	**21,102**	13,126	1,172	14,298

24. Investments in jointly controlled entities

The significant jointly controlled entities of the BP group at 31 December 2012 are shown in Note 45. Summarized financial information for the group's share of jointly controlled entities is shown below. Balance sheet information shown below excludes data relating to jointly controlled entities reclassified as assets held for sale as at the end of the period. Income statement information shown below includes data relating to jointly controlled entities reclassified as assets held for sale during the period up until their date of reclassification as held for sale.

			$ million
	2012	2011	2010
Sales and other operating revenues	**16,237**	15,720	11,679
Profit before interest and taxation	**1,331**	1,918	1,730
Finance costs	**129**	134	122
Profit before taxation	**1,202**	1,784	1,608
Taxation	**458**	480	433
Profit for the year	**744**	1,304	1,175
Non-current assets	**17,945**	16,495	
Current assets	**4,374**	4,613	
Total assets	**22,319**	21,108	
Current liabilities	**3,014**	2,553	
Non-current liabilities	**4,410**	3,980	
Total liabilities	**7,424**	6,533	
	14,895	14,575	
Group investment in jointly controlled entities			
Group share of net assets (as above)	**14,895**	14,575	
Loans made by group companies to jointly controlled entities	**829**	943	
	15,724	15,518	

Transactions between the group and its jointly controlled entities are summarized below.

						$ million
Sales to jointly controlled entities		**2012**		2011		2010
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	**6,423**	**1,713**	5,095	1,616	3,804	1,352

						$ million
Purchases from jointly controlled entities		**2012**		2011		2010
Product	**Purchases**	**Amount payable at 31 December**[a]	Purchases	Amount payable at 31 December[a]	Purchases	Amount payable at 31 December[a]
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**7,641**	**516**	7,798	369	8,063	683

[a] In addition to the amounts shown above, there are amounts payable to jointly controlled entities of $1,222 million (2011 $2,256 million and 2010 $2,583 million) 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 $757 million (2011 $605 million), part of which is a reimbursement balance relating to pensions that will be received over several years. 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.

BP has commitments amounting to $4,391 million (2011 $4,155 million) in relation to contracts with jointly controlled entities for the purchase of LNG, crude oil and oil products, refinery operating costs and storage and handling services. See Note 44 for further information on capital commitments relating to BP's investments in jointly controlled entities.

25. Investments in associates

The significant associates of the BP group at 31 December 2012 are shown in Note 45. Summarized financial information for the group's share of associates is set out below. Balance sheet information shown below excludes data relating to associates reclassified as assets held for sale as at the end of the period. Income statement information shown below includes data relating to associates reclassified as assets held for sale for the period up until their date of reclassification as held for sale.

$ million

			2012			2011			2010
	TNK-BP	**Other**	**Total**	TNK-BP	Other	Total	TNK-BP	Other	Total
Sales and other operating revenues	**24,675**	**11,965**	**36,640**	30,100	12,145	42,245	22,323	10,031	32,354
Profit before interest and taxation	**4,405**	**906**	**5,311**	5,992	958	6,950	3,866	1,215	5,081
Finance costs	**84**	**16**	**100**	132	13	145	128	22	150
Profit before taxation	**4,321**	**890**	**5,211**	5,860	945	6,805	3,738	1,193	4,931
Taxation	**979**	**201**	**1,180**	1,333	214	1,547	913	228	1,141
Minority interest	**356**	**–**	**356**	342	–	342	208	–	208
Profit for the year	**2,986**	**689**	**3,675**	4,185	731	4,916	2,617	965	3,582
Non-current assets			**3,270**	16,172	3,865	20,037			
Current assets			**2,399**	4,210	2,273	6,483			
Total assets			**5,669**	20,382	6,138	26,520			
Current liabilities			**2,126**	3,086	2,149	5,235			
Non-current liabilities			**1,290**	6,416	1,744	8,160			
Total liabilities			**3,416**	9,502	3,893	13,395			
Minority interest			**–**	867	–	867			
			2,253	10,013	2,245	12,258			
Group investment in associates									
Group share of net assets (as above)			**2,253**	10,013	2,245	12,258			
Loans made by group companies to associates			**745**	–	1,033	1,033			
			2,998	10,013	3,278	13,291			

Transactions between the group and its associates are summarized below.

$ million

Sales to associates		**2012**		2011		2010
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	**3,771**	**401**	3,855	393	3,561	330

$ million

Purchases from associates		**2012**		2011		2010
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	**9,135**	**915**	8,159	815	4,889	633

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 2012, as shown in the table above, exclude $159 million (2011 $220 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 2012 of $34 million (2011 $38 million) are also excluded from the table above.

BP has commitments amounting to $595 million (2011 $1,477 million) in relation to contracts with its associates for the purchase of crude oil and oil products, transportation and storage. See Note 44 for further information on capital commitments relating to BP's investments in associates.

On 18 October 2010, BP announced that it had reached agreement to sell assets in Vietnam, together with its upstream businesses and associated interests in Venezuela, to TNK-BP. As at 31 December 2010, a deposit of $1 billion had been received from TNK-BP in advance of completion of this transaction and was reported within finance debt on the group balance sheet. This deposit was not reflected in the amount payable in the table above. These sales completed during 2011.

25. Investments in associates continued

On 22 November 2012, BP, Rosneft and Rosneftegaz (the state-owned parent company of Rosneft) signed definitive and binding agreements for the sale of BP's 50% interest in TNK-BP to Rosneft and for BP's investment in Rosneft. BP and Rosneft announced heads of terms for this transaction on 22 October 2012, after which our investment was classified as an asset held for sale and therefore equity accounting ceased. See Note 4 for further information. Summarized financial information for the group's share of TNK-BP for the full year 2012 and at 31 December 2012 is set out below.

	$ million
	2012
Sales and other operating revenues	**30,226**
Profit before interest and taxation	**5,441**
Profit for the year	**3,726**
Non-current assets	**18,243**
Current assets	**5,459**
Total assets	**23,702**
Current liabilities	**3,778**
Non-current liabilities	**6,465**
Total liabilities	**10,243**
Minority interest	**1,071**
	12,388

26. 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							$ million **2012**
	Note	**Loans and receivables**	**Available-for-sale financial assets**	**At fair value through profit or loss**	**Derivative hedging instruments**	**Financial liabilities measured at amortized cost**	**Total carrying amount**
Financial assets							
Other investments – equity shares	**27**	**–**	**1,431**	**–**	**–**	**–**	**1,431**
– other	**27**	**–**	**1,005**	**585**	**–**	**–**	**1,590**
Loans		**942**	**–**	**–**	**–**	**–**	**942**
Trade and other receivables	**29**	**34,814**	**–**	**–**	**–**	**–**	**34,814**
Derivative financial instruments	**33**	**–**	**–**	**5,342**	**3,459**	**–**	**8,801**
Cash and cash equivalents	**30**	**15,043**	**4,505**	**–**	**–**	**–**	**19,548**
Financial liabilities							
Trade and other payables	**32**	**–**	**–**	**–**	**–**	**(44,706)**	**(44,706)**
Derivative financial instruments	**33**	**–**	**–**	**(5,093)**	**(288)**	**–**	**(5,381)**
Accruals		**–**	**–**	**–**	**–**	**(7,258)**	**(7,258)**
Finance debt	**34**	**–**	**–**	**–**	**–**	**(48,165)**	**(48,165)**
		50,799	**6,941**	**834**	**3,171**	**(100,129)**	**(38,384)**

At 31 December							$ million 2011
	Note	Loans and receivables	Available-for-sale financial assets	At fair value through profit or loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
Financial assets							
Other investments – equity shares	27	–	1,128	–	–	–	1,128
– other	27	–	1,277	516	–	–	1,793
Loans		1,128	–	–	–	–	1,128
Trade and other receivables	29	36,879	–	–	–	–	36,879
Derivative financial instruments	33	–	–	7,188	1,707	–	8,895
Cash and cash equivalents	30	9,750	4,317	–	–	–	14,067
Financial liabilities							
Trade and other payables	32	–	–	–	–	(50,651)	(50,651)
Derivative financial instruments	33	–	–	(6,436)	(557)	–	(6,993)
Accruals		–	–	–	–	(6,321)	(6,321)
Finance debt	34	–	–	–	–	(44,183)	(44,183)
		47,757	6,722	1,268	1,150	(101,155)	(44,258)

The fair value of finance debt is shown in Note 34. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

26. Financial instruments and financial risk factors continued

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 group 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 the activities in the financial markets are managed by the treasury function, working under the compliance and control structure of the integrated supply and trading 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. 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.

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 primary commodity price risks that the group is exposed to include oil, natural gas and power prices 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 the 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 Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market prices over a one-day holding 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.

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.

Value-at-risk limits are in place for each trading activity and for the group's trading activity in total. The board has delegated a 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				**2012**				2011
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Group trading	**51**	**19**	**34**	**25**	83	28	42	28
Oil price trading	**50**	**18**	**31**	**23**	84	23	39	27
Gas and power trading	**30**	**4**	**12**	**8**	20	6	11	7

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 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 $16 million at 31 December 2012 (2011 $23 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 $1,112 million at 31 December 2012 (2011 liability of $1,417 million). Key information on the natural gas contracts is given below.

At 31 December	**2012**	2011
Remaining contract terms	**2 years and 5 months to 5 years and 9 months**	3 years and 5 months to 6 years and 9 months
Contractual/notional amount	**117 million therms**	952 million therms

26. 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				**2012**				2011
	Gas price	**Oil price**	**Power price**	**Discount rate**	Gas price	Oil price	Power price	Discount rate
Favourable 10% change	**16**	**90**	**10**	**2**	100	74	4	5
Unfavourable 10% change	**(33)**	**(95)**	**(10)**	**(2)**	(109)	(77)	(4)	(5)

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 included within oil price 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 translation 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 aims to manage such risk to keep the 12-month foreign currency value at risk below $200 million. At 31 December 2012, the foreign currency value at risk was $71 million (2011 $100 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 33.

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, euro, Norwegian krone, Australian dollar and Korean won and at 31 December 2012 open contracts were in place for $853 million sterling, $104 million euro, $172 million Norwegian krone, $112 million Australian dollar and $153 million Korean won capital expenditures maturing within seven years, with over 68% of the deals maturing within two years (2011 $1,242 million sterling, $158 million euro, $118 million Norwegian krone, $210 million Australian dollar and $230 million Korean won capital expenditures maturing within five years, with over 69% of the deals maturing within two years).

For other UK, European 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 2012, the open positions relating to cylinders consisted of receive sterling, pay US dollar, purchased call and sold put options (cylinders) for $2,886 million (2011 $2,683 million); receive euro, pay US dollar cylinders for $1,636 million (2011 $1,304 million); receive Australian dollar, pay US dollar cylinders for $522 million (2011 $312 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 2012, the total foreign currency net borrowings not swapped into US dollars amounted to $361 million (2011 $371 million). Of this total, $142 million was denominated in currencies other than the functional currency of the individual operating unit being entirely Canadian dollars (2011 $129 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 $14 million (2011 $13 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 included within oil price 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 floating rate exposure, mainly to US dollar floating, but in certain defined circumstances maintains a US dollar fixed rate exposure for a proportion of debt. The proportion of floating rate debt net of interest rate swaps and excluding disposal deposits at 31 December 2012 was 65% of total finance debt outstanding (2011 65%). The weighted average interest rate on finance debt at 31 December 2012 is 2% (2011 2%) and the weighted average maturity of fixed rate debt is four years (2011 five years).

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 2013, it is estimated that the group's finance costs for 2013 would increase by approximately $311 million (2011 $289 million increase in 2012). 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 2012 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.

26. Financial instruments and financial risk factors continued

(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 the years presented relating to listed non-current available-for-sale investments. For further information see Note 27. In addition, at 31 December 2012, the group was a party to certain equity price derivatives described in further detail below.

At 31 December 2012, it is estimated that an increase of 10% in quoted equity prices would result in an immediate credit to other comprehensive income of $1,502 million (2011 $87 million credit to other comprehensive income), while a decrease of 10% in quoted equity prices would result in an immediate charge to other comprehensive income of $1,502 million (2011 $87 million charge to other comprehensive income). At 31 December 2012, 82% (2011 77%) of the carrying amount of non-current available-for-sale equity financial assets represented the group's 1.25% stake in Rosneft, thus the group's exposure is concentrated on changes in the share price of this equity in particular. As described in Note 33, the agreements for the purchase of 5.66% and 9.80% shareholdings in Rosneft are derivative financial instruments, whose fair value is impacted by the Rosneft share price, and are accounted for as cash flow hedges, with changes in fair value recognized in other comprehensive income to the extent the hedge is effective. See Note 4 for further information.

(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 include segregation of credit approval authorities from any sales, marketing or trading teams authorized to incur credit risk; the establishment of credit systems and processes to ensure that all counterparty exposure is rated and that all counterparty exposure and limits can be monitored and reported; and the timely identification and reporting of any non-approved credit exposures and credit losses. While each segment of the group is typically responsible for its own credit risk management and reporting consistent with group policy, the treasury function holds group-wide credit risk authority and oversight responsibility for exposure to banks and financial institutions.

The global credit environment remained challenging in 2012, suffering not only from continuing economic and political uncertainties but also from key event risks, causing the group to further heighten awareness, discussion and co-ordination of the material credit risks arising from its activities.

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. 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, letters of credit, trade credit insurance, liens, third-party guarantees and other forms of credit mitigation. 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. Collateral received and recognized in the balance sheet at the year end was $334 million (2011 $273 million) and collateral held off balance sheet was $148 million (2011 $6 million). As at 31 December 2012, the group had in place other credit enhancements designed to mitigate approximately $11.5 billion of credit risk (2011 $8.6 billion). Credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2012 were $237 million (2011 $415 million) in respect of liabilities of jointly controlled entities and associates and $713 million (2011 $1,430 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.

For the contracts comprising derivative financial instruments in an asset position at 31 December 2012, excluding the contracts with Rosneft accounted for as derivatives, it is estimated that over 72% (2011 over 76%) of the unmitigated credit exposure is to counterparties of investment grade credit quality.

For cash and cash equivalents, the treasury function dynamically manages bank deposit limits to ensure cash is well-diversified and to reduce concentration risks. At 31 December 2012, over 98% of the cash and cash equivalents balance was deposited with financial institutions rated at least A- by Standard & Poor's and A3 by Moody's. Direct cash and cash equivalent exposures to Greek, Italian, Irish, Portuguese and Spanish financial institutions totalled less than 0.6% of total cash and cash equivalents.

26. Financial instruments and financial risk factors continued

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 70-80% (2011 approximately 70-80%) of the unmitigated trade receivables portfolio exposure is of investment grade credit quality. Current assets, including trade and other receivables, in Egypt amount to $3.0 billion (see page 69), of which over one third relates to trade receivables which are not impaired but are past the original due date. Management is working with the counterparties to continue to collect these amounts.

		$ million
Trade and other receivables at 31 December	**2012**	2011
Neither impaired nor past due	**31,916**	34,563
Impaired (net of valuation allowance)	**80**	33
Not impaired and past due in the following periods		
within 30 days	**1,334**	1,263
31 to 60 days	**285**	250
61 to 90 days	**224**	132
over 90 days	**975**	638
	34,814	36,879

The movement in the impairment provision for trade receivables is set out below.

		$ million
	2012	2011
At 1 January	**332**	428
Exchange adjustments	**7**	(16)
Charge for the year	**240**	115
Utilization	**(65)**	(124)
Write back	**(25)**	(71)
At 31 December	**489**	332

(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 its own current cash holdings and future cash generation including disposal proceeds, the commercial paper markets and by using undrawn committed borrowing facilities to meet foreseeable liquidity requirements.

The group has in place a European Debt Issuance Programme (DIP) under which the group may raise up to $20 billion of debt for maturities of one month or longer. At 31 December 2012, the amount drawn down against the DIP was $14,043 million (2011 $11,582 million). The group also had in place an unlimited US Shelf Registration throughout 2012 and until 5 February 2013, under which it could raise debt with maturities of one month or longer. From 5 February 2013 the Well-known Seasoned Issuer (WKSI) shelf was converted to a non-WKSI shelf with a limit of $30 billion, with no draw down since the conversion. In addition, the group has an Australian Note Issue Programme of A$5 billion, and as at 31 December 2012 the amount drawn down was A$500 million (2011 nil).

The group had a long-term debt rating of A2 (stable outlook) assigned by Moody's consistently throughout the year, and a rating of A (positive outlook) assigned by Standard & Poor's since July 2012, strengthened from A (stable outlook) in force at the start of the year.

During 2012, $10.9 billion of long-term taxable bonds were issued with tenors of three to 10 years. Flexible commercial paper is issued at competitive rates to meet short-term borrowing requirements as and when needed.

As a further liquidity measure, the group continues to maintain suitable levels of cash and cash equivalents, amounting to $19.5 billion at 31 December 2012, invested with highly rated banks or money market funds and readily accessible at immediate and short notice (2011 $14.1 billion). At 31 December 2012, the group had substantial amounts of undrawn borrowing facilities available, consisting of $6,825 million of standby facilities available to draw and repay until mid-March 2014. These facilities were renegotiated during 2011 with 23 international banks, and borrowings under them would be at pre-agreed rates.

The group also has committed letter of credit (LC) facilities totalling $6,925 million with a number of banks for a one-year duration, allowing LCs to be issued to a maximum one-year duration. There were also uncommitted secured LC evergreen facilities in place at 31 December 2012 for $2,160 million, secured against inventories or receivables when utilized.

The amounts shown for finance debt in the table below include future minimum lease payments with respect to finance leases.

26. Financial instruments and financial risk factors continued

Current finance debt on the group balance sheet at 31 December 2012 includes $632 million (2011 $30 million) in respect of cash deposits received for disposals expected to complete in 2013, which will be considered extinguished on completion of the transactions. This amount is excluded from the table below.

The table also shows the timing of cash outflows relating to trade and other payables and accruals.

								$ million
				2012				2011
	Trade and other payables	Accruals	Finance debt	Interest relating to finance debt	Trade and other payables[a]	Accruals	Finance debt	Interest relating to finance debt
Within one year	**43,001**	**6,810**	**9,398**	**893**	47,678	5,933	9,013	1,011
1 to 2 years	**893**	**134**	**5,906**	**755**	1,605	137	7,094	772
2 to 3 years	**385**	**79**	**5,902**	**634**	569	55	6,703	608
3 to 4 years	**318**	**52**	**6,024**	**510**	449	26	5,019	468
4 to 5 years	**52**	**48**	**5,797**	**388**	259	49	4,278	356
5 to 10 years	**24**	**84**	**14,790**	**885**	31	82	11,574	806
Over 10 years	**33**	**51**	**348**	**50**	72	39	502	71
	44,706	**7,258**	**48,165**	**4,115**	50,663	6,321	44,183	4,092

[a] Trade and other payables at 31 December 2011 included the Gulf of Mexico oil spill trust fund liability amounting to $4,884 million which was payable within one year.

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 33. 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 $8,620 million at 31 December 2012 (2011 $9,099 million) to be received on the same day as the related cash outflows. Also not shown are the expected cash outflows under the Rosneft share purchase agreements described in Note 33, nor the related expected cash inflows for the sale of our 50% interest in TNK-BP.

		$ million
	2012	2011
Within one year	**1,356**	1,738
1 to 2 years	**1,107**	1,372
2 to 3 years	**295**	1,115
3 to 4 years	**1,261**	298
4 to 5 years	**2,577**	1,262
5 to 10 years	**1,903**	3,459
	8,499	9,244

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.

27. Other investments

				$ million
		2012		2011
	Current	**Non-current**	Current	Non-current
Equity investments – listed	**–**	**1,182**	–	876
– unlisted	**–**	**249**	–	252
Repurchased gas pre-paid bonds	**303**	**686**	288	989
Other	**16**	**585**	–	516
	319	**2,702**	288	2,633

Equity investments have no fixed maturity date or coupon rate, and are classified as available-for-sale financial assets. As such they are recorded at fair value with the gain or loss arising as a result of changes in fair value recorded in other comprehensive income. 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.

The most significant listed investment is the group's 1.25% stake in Rosneft which had a fair value of $1,179 million at 31 December 2012 (2011 $873 million). The fair value gain arising on revaluation of this investment during 2012 has been recorded within other comprehensive income.

In 2012, impairment losses of $6 million were recognized relating to unlisted investments (2011 $12 million and 2010 nil); there were no impairment losses relating to listed investments in 2012, 2011 or 2010.

27. Other investments continued

Other non-current investments at 31 December 2012 include $585 million relating to life insurance policies. In the 2011 Annual Report and Form 20-F the corresponding amount of $516 million was included in non-current prepayments. This amount has been reclassified to other non-current investments in the balance sheet comparative figures shown in this Annual Report and Form 20-F. The life insurance policies have been designated as financial assets at fair value through profit or loss and their valuation methodology is in level 3 of the fair value hierarchy. Fair value gains of $70 million were recognized in the income statement (2011 $21 million and 2010 $58 million).

BP has entered into long-term gas supply contracts which are backed by gas pre-paid bonds. In 2010, BP was unsuccessful in the remarketing of these bonds and repurchased them. The outstanding bonds associated with these long-term gas supply contracts held by BP are recorded within other investments, with the related liability recorded within other payables on the balance sheet. The fair value of the gas pre-paid bonds is the same as the carrying amount, as the bonds are based on floating rate interest with weekly market re-set, and as such are in level 1 of the fair value hierarchy.

28. Inventories

		$ million
	2012	2011
Crude oil	**9,123**	7,702
Natural gas	**187**	178
Refined petroleum and petrochemical products	**15,149**	14,909
	24,459	22,789
Supplies	**2,408**	2,057
	26,867	24,846
Trading inventories	**1,000**	815
	27,867	25,661
Cost of inventories expensed in the income statement	**293,242**	285,618

The inventory valuation at 31 December 2012 is stated net of a provision of $124 million (2011 $152 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 a credit of $28 million (2011 $111 million debit). Inventories with a carrying amount of $64 million (2011 nil) had been pledged as security for certain of the group's liabilities at 31 December 2012.

29. Trade and other receivables

				$ million
	2012		2011	
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**25,977**	**151**	27,929	508
Amounts receivable from jointly controlled entities	**952**	**761**	1,004	612
Amounts receivable from associates	**492**	**102**	492	159
Other receivables	**5,677**	**702**	5,429	746
	33,098	**1,716**	34,854	2,025
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**4,178**	**2,264**	8,233	1,642
Other receivables	**388**	**774**	439	670
	4,566	**3,038**	8,672	2,312
	37,664	**4,754**	43,526	4,337

[a] See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 26 for further information.

30. Cash and cash equivalents

		$ million
	2012	2011
Cash at bank and in hand	**5,800**	4,872
Term bank deposits	**9,243**	4,878
Cash equivalents	**4,505**	4,317
	19,548	14,067

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 2012 includes $1,544 million (2011 $901 million) that is restricted. This relates principally to amounts required to cover initial margin on trading exchanges and $709 million relating to the dividend received from TNK-BP in December 2012 which meets the criteria to be treated as restricted cash until completion of the anticipated sale of BP's interest in TNK-BP to Rosneft. See Note 4 and Note 26 for further information.

31. Valuation and qualifying accounts

$ million

	2012		2011		2010	
	Accounts receivable	**Fixed asset investments**	Accounts receivable	Fixed asset investments	Accounts receivable	Fixed asset investments
At 1 January	**332**	**643**	428	540	430	349
Charged to costs and expenses	**240**	**196**	115	111	150	376
Charged to other accounts[a]	**7**	**18**	(16)	(3)	(9)	(3)
Deductions	**(90)**	**(508)**	(195)	(5)	(143)	(182)
At 31 December	**489**	**349**	332	643	428	540

[a] Principally currency transactions.

Valuation and qualifying accounts comprise impairment provisions for accounts receivable and fixed asset investments, and are deducted in the balance sheet from the assets to which they apply.

32. Trade and other payables

$ million

	2012		2011	
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**29,703**	**–**	29,830	–
Amounts payable to jointly controlled entities	**1,580**	**158**	1,578	1,047
Amounts payable to associates	**972**	**102**	876	159
Gulf of Mexico oil spill trust fund liability[a]	**22**	**–**	4,872	–
Other payables	**10,723**	**1,446**	10,510	1,779
	43,000	**1,706**	47,666	2,985
Non-financial liabilities				
Other payables	**4,154**	**396**	4,739	452
	47,154	**2,102**	52,405	3,437

[a] See Note 2 for further information.

Trade and other payables are predominantly non-interest bearing. See Note 26 for further information.

33. 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 26.

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. At 31 December 2012, the group was also party to certain equity price derivatives arising in connection with the anticipated completion of the transaction with Rosneft – see below for further information.

IAS 39 prescribes strict criteria for hedge accounting, 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 carrying amounts of derivative financial instruments at 31 December are set out below.

				$ million
		2012		2011
	Asset	**Liability**	Asset	Liability
Derivatives held for trading				
Currency derivatives	**175**	**(189)**	217	(217)
Oil price derivatives	**841**	**(707)**	823	(536)
Natural gas price derivatives	**3,536**	**(2,496)**	5,305	(3,603)
Power price derivatives	**719**	**(589)**	843	(663)
Equity price derivatives	**71**	**–**	–	–
	5,342	**(3,981)**	7,188	(5,019)
Embedded derivatives				
Commodity price contracts	**–**	**(1,112)**	–	(1,417)
	–	**(1,112)**	–	(1,417)
Cash flow hedges				
Equity price derivatives	**1,339**	**–**	–	–
Currency forwards, futures and cylinders	**51**	**(41)**	25	(159)
Cross-currency interest rate swaps	**1**	**–**	–	–
	1,391	**(41)**	25	(159)
Fair value hedges				
Currency forwards, futures and swaps	**875**	**(247)**	842	(398)
Interest rate swaps	**1,193**	**–**	840	–
	2,068	**(247)**	1,682	(398)
	8,801	**(5,381)**	8,895	(6,993)
Of which – current	**4,507**	**(2,658)**	3,857	(3,220)
– non-current	**4,294**	**(2,723)**	5,038	(3,773)

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 26.

33. Derivative financial instruments continued

The following tables show further information on the derivatives and other financial instruments held for trading purposes. Derivative assets held for trading have the following carrying amounts and maturities.

							$ million
							2012
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	169	6	–	–	–	–	175
Oil price derivatives	656	109	38	21	12	5	841
Natural gas price derivatives	1,532	711	418	259	144	472	3,536
Power price derivatives	327	188	114	62	19	9	719
Equity price derivatives	71	–	–	–	–	–	71
	2,755	1,014	570	342	175	486	5,342

							$ million
							2011
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	194	18	5	–	–	–	217
Oil price derivatives	573	135	77	25	10	3	823
Natural gas price derivatives	2,493	1,160	597	346	207	502	5,305
Power price derivatives	498	160	101	54	30	–	843
	3,758	1,473	780	425	247	505	7,188

Derivative liabilities held for trading have the following carrying amounts and maturities.

							$ million
							2012
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	(189)	–	–	–	–	–	(189)
Oil price derivatives	(580)	(77)	(27)	(12)	(8)	(3)	(707)
Natural gas price derivatives	(1,199)	(440)	(241)	(135)	(78)	(403)	(2,496)
Power price derivatives	(341)	(133)	(59)	(21)	(10)	(25)	(589)
	(2,309)	(650)	(327)	(168)	(96)	(431)	(3,981)

							$ million
							2011
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(168)	(49)	–	–	–	–	(217)
Oil price derivatives	(483)	(37)	(7)	(4)	(3)	(2)	(536)
Natural gas price derivatives	(1,696)	(876)	(347)	(197)	(102)	(385)	(3,603)
Power price derivatives	(328)	(176)	(89)	(46)	(24)	–	(663)
	(2,675)	(1,138)	(443)	(247)	(129)	(387)	(5,019)

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 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
			2012		2011
	Oil price	**Power price**	**Natural gas price**	Power price	Natural gas price
Fair value of contracts not recognized through the income statement at 1 January	–	9	114	–	69
Fair value of new contracts at inception not recognized in the income statement	(1)	(4)	28	9	51
Fair value recognized in the income statement	1	(9)	(19)	–	(6)
Fair value of contracts not recognized through the income statement at 31 December	–	(4)	123	9	114

33. 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
							2012
	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	**187**	**6**	**–**	**–**	**–**	**–**	**193**
Level 2	**3,766**	**1,088**	**520**	**216**	**46**	**10**	**5,646**
Level 3	**302**	**184**	**137**	**136**	**136**	**478**	**1,373**
	4,255	**1,278**	**657**	**352**	**182**	**488**	**7,212**
Less: netting by counterparty	**(1,500)**	**(264)**	**(87)**	**(10)**	**(7)**	**(2)**	**(1,870)**
	2,755	**1,014**	**570**	**342**	**175**	**486**	**5,342**
Fair value of derivative liabilities							
Level 1	**(189)**	**–**	**–**	**–**	**–**	**–**	**(189)**
Level 2	**(3,476)**	**(810)**	**(315)**	**(78)**	**(19)**	**(28)**	**(4,726)**
Level 3	**(144)**	**(104)**	**(99)**	**(100)**	**(84)**	**(405)**	**(936)**
	(3,809)	**(914)**	**(414)**	**(178)**	**(103)**	**(433)**	**(5,851)**
Less: netting by counterparty	**1,500**	**264**	**87**	**10**	**7**	**2**	**1,870**
	(2,309)	**(650)**	**(327)**	**(168)**	**(96)**	**(431)**	**(3,981)**
Net fair value	**446**	**364**	**243**	**174**	**79**	**55**	**1,361**

							$ million
							2011[a]
	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	229	18	5	–	–	–	252
Level 2	6,526	1,724	639	268	80	8	9,245
Level 3	338	305	262	221	170	500	1,796
	7,093	2,047	906	489	250	508	11,293
Less: netting by counterparty	(3,335)	(574)	(126)	(64)	(3)	(3)	(4,105)
	3,758	1,473	780	425	247	505	7,188
Fair value of derivative liabilities							
Level 1	(168)	(49)	–	–	–	–	(217)
Level 2	(5,652)	(1,499)	(412)	(163)	(20)	(7)	(7,753)
Level 3	(190)	(164)	(157)	(148)	(112)	(383)	(1,154)
	(6,010)	(1,712)	(569)	(311)	(132)	(390)	(9,124)
Less: netting by counterparty	3,335	574	126	64	3	3	4,105
	(2,675)	(1,138)	(443)	(247)	(129)	(387)	(5,019)
Net fair value	1,083	335	337	178	118	118	2,169

[a] The presentation of certain comparative data for 2011 before netting has been amended.

33. 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
	Oil price	**Natural gas price**	**Power price**	**Equity price**	**Total**
Net fair value of contracts at 1 January 2012	**162**	**408**	**13**	**–**	**583**
Gains (losses) recognized in the income statement	**30**	**4**	**(4)**	**–**	**30**
New contracts	**–**	**–**	**–**	**71**	**71**
Settlements	**(87)**	**(56)**	**–**	**–**	**(143)**
Transfers into level 3	**–**	**(19)**	**–**	**–**	**(19)**
Transfers out of level 3	**–**	**(33)**	**(51)**	**–**	**(84)**
Exchange adjustments	**–**	**–**	**(1)**	**–**	**(1)**
Net fair value of contracts at 31 December 2012	**105**	**304**	**(43)**	**71**	**437**

				$ million
	Oil price	Natural gas price	Power price	Total
Net fair value of contracts at 1 January 2011	164	667	(1)	830
Gains (losses) recognized in the income statement	69	129	11	209
Settlements	(71)	(110)	3	(178)
Transfers out of level 3	–	(278)	–	(278)
Net fair value of contracts at 31 December 2011	162	408	13	583

Transfers out of level 3 of the fair value hierarchy in 2012 relate primarily to the delivery dates for a number of natural gas and power forward contracts moving into a time period where market observable prices are available, and therefore being reclassified to level 2 of the fair value hierarchy.

The amount recognized in the income statement for the year relating to level 3 held for trading derivatives still held at 31 December 2012 was a $10 million gain (2011 $204 million gain relating to derivatives still held at 31 December 2011).

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, and relate to both currency and commodity trading activities. 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 these items was a net loss of $726 million (2011 $934 million net loss and 2010 $1,738 million net gain).

Embedded derivatives

The group has embedded derivatives, the majority of which relate to certain natural gas contracts. 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 commodity price embedded derivatives relate to natural gas contracts, are categorized in level 3 of the fair value hierarchy and 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.

33. Derivative financial instruments continued

Embedded derivative liabilities relate mainly to commodity price contracts and have the following fair values and maturities.

							$ million
							2012
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Net fair value	**(322)**	**(299)**	**(252)**	**(151)**	**(57)**	**(31)**	**(1,112)**

							$ million
							2011
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Net fair value	(347)	(319)	(306)	(236)	(134)	(75)	(1,417)

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
	2012	2011
	Commodity price	Commodity price
Net fair value of contracts at 1 January	**(1,417)**	(1,607)
Settlements	**375**	301
Losses recognized in the income statement	**(6)**	(106)
Exchange adjustments	**(64)**	(5)
Net fair value of contracts at 31 December	**(1,112)**	(1,417)

The amount recognized in the income statement for the year relating to level 3 embedded derivatives still held at 31 December 2012 was a loss of $6 million (2011 $106 million loss relating to embedded derivatives still held at 31 December 2011).

The fair value gain (loss) on embedded derivatives is shown below.

			$ million
	2012	2011	2010
Commodity price embedded derivatives	**347**	190	(309)
Other embedded derivatives	**–**	(122)	–
Fair value gain (loss)	**347**	68	(309)

Cash flow hedges

At 31 December 2012, 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, categorized in level 2 of the fair value hierarchy. Note 26 outlines the management of risk aspects for currency 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 $62 million (2011 $195 million gain and 2010 $25 million gain). The entire loss of $62 million is included in production and manufacturing expenses (2011 $195 million gain in production and manufacturing expenses; 2010 $25 million gain in production and manufacturing expenses). The amount removed from equity during the period and included in the carrying amount of non-financial assets was a loss of $19 million (2011 $13 million gain and 2010 $53 million loss). The amounts retained in equity at 31 December 2012 in relation to these cash flow hedges consist of deferred losses of $18 million maturing in 2013 and deferred gains of $9 million maturing in 2015 and beyond.

The anticipated transaction whereby BP expects to sell its 50% interest in TNK-BP and acquire 18.5% of Rosneft, as described in Note 4, comprises three agreements which, during the period from signing until completion, represent derivative financial instruments that are required to be measured at fair value. BP has designated two of the agreements, for the acquisition of a 5.66% shareholding in Rosneft from Rosneftegaz, and for the acquisition of a 9.80% shareholding from Rosneft, as hedging instruments in a cash flow hedge, and so changes in the fair values of these agreements are recognized in other comprehensive income. The third agreement, under which BP expects to sell its 50% interest in TNK-BP in exchange for cash and a 3.04% shareholding in Rosneft, is also a derivative financial instrument, but its fair value cannot be reliably measured. An asset of $1,410 million related to these agreements was recognized on the balance sheet at 31 December 2012, of which $1,339 million relates to the fair value of the cash flow hedge derivatives. The derivatives measured at fair value at 31 December 2012 are categorized in level 3 of the fair value hierarchy using inputs that include the quoted Rosneft share price. A credit of $1,410 million recognized in other comprehensive income would be recycled to the income statement only if the investment in Rosneft is sold or impaired.

Fair value hedges

At 31 December 2012, 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, categorized in level 2 of the fair value hierarchy. The effectiveness of each hedge relationship is quantitatively assessed and demonstrated to continue to be highly effective. The gain on the hedging derivative instruments taken to the income statement in 2012 was $536 million (2011 $328 million and 2010 $563 million) offset by a loss on the fair value of the finance debt of $537 million (2011 $327 million and 2010 $554 million).

The interest rate and cross-currency interest rate swaps mature within one to 10 years, with an average maturity of four to five years (2011 four to five 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 26 outlines the group's approach to interest rate and currency risk management.

34. Finance debt

						$ million
			2012			2011
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**9,369**	**38,412**	**47,781**	8,675	34,816	43,491
Net obligations under finance leases	**29**	**355**	**384**	339	353	692
	9,398	**38,767**	**48,165**	9,014	35,169	44,183
Disposal deposits	**632**	**–**	**632**	30	–	30
	10,030	**38,767**	**48,797**	9,044	35,169	44,213

The main elements of current borrowings are the current portion of long-term borrowings that are due to be repaid in the next 12 months of $6,240 million (2011 $4,875 million) and issued commercial paper of $3,028 million (2011 $3,635 million). Finance debt does not include accrued interest, which is reported within other payables.

Deposits for disposal transactions expected to complete in 2013 of $632 million are also included in current finance debt (2011 $30 million for transactions expected to complete in 2012). This unsecured debt will be considered extinguished on completion of the transactions.

At 31 December 2012, $142 million (2011 $131 million) of finance debt was secured by the pledging of assets. At 31 December 2011, in connection with $2,344 million of finance debt, BP had entered into crude oil sale contracts in respect of oil produced from certain fields in offshore Angola and Azerbaijan to provide security to lending banks. These loans were repaid during the fourth quarter of 2012 and the sales contracts were terminated.

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. The disposal deposits noted above are excluded from this analysis.

			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**
						2012
US dollar	**3**	**4**	**16,744**	**1**	**26,208**	**42,952**
Euro	**5**	**2**	**20**	**1**	**4,851**	**4,871**
Other currencies	**4**	**11**	**255**	**3**	**87**	**342**
			17,019		**31,146**	**48,165**
						2011
US dollar	4	5	15,016	1	27,285	42,301
Euro	5	3	25	3	1,575	1,600
Other currencies	4	12	240	3	42	282
			15,281		28,902	44,183

The euro debt not swapped to US dollar is naturally hedged for the foreign currency risk by holding equivalent euro cash and cash equivalent amounts.

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. The terms and conditions of these finance leases do not impose significant financial restrictions on the group. Future minimum lease payments under finance leases are set out below.

		$ million
	2012	2011
Future minimum lease payments payable within		
1 year	**59**	454
2 to 5 years	**211**	200
Thereafter	**334**	380
	604	1,034
Less: finance charges	**220**	342
Net obligations	**384**	692
Of which – payable within 1 year	**29**	339
– payable within 2 to 5 years	**109**	99
– payable thereafter	**246**	254

34. 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 2012, whereas in the balance sheet the amount is reported within current finance debt. The disposal deposits noted above are excluded from this analysis.

The carrying amount of the group's short-term borrowings, comprising mainly commercial paper, 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
		2012		2011
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**3,128**	**3,128**	3,800	3,800
Long-term borrowings	**45,969**	**44,653**	40,606	39,691
Net obligations under finance leases	**520**	**384**	776	692
Total finance debt	**49,617**	**48,165**	45,182	44,183

35. Capital disclosures and analysis of changes in net debt

The group defines capital as total equity. The group's approach to managing capital is set out in its financial framework which BP continues to refine to support the pursuit of value growth for shareholders, whilst maintaining a secure financial base. BP intends to maintain a net debt ratio within the 10-20% gearing range, and continue to hold a significant liquidity buffer while uncertainties remain.

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, less 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 applied, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. BP believes 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. 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. At 31 December 2012, the net debt ratio was 18.7% (2011 20.5%).

During 2012 and 2011, the company did not repurchase any of its own shares, other than as needed to satisfy the requirements of certain employee share-based payment plans.

		$ million
At 31 December	**2012**	2011
Gross debt	**48,797**	44,213
Less: fair value asset of hedges related to finance debt	**1,700**	1,133
	47,097	43,080
Less: cash and cash equivalents	**19,548**	14,067
Net debt	**27,549**	29,013
Equity	**119,620**	112,482
Net debt ratio	**18.7%**	20.5%

An analysis of changes in net debt is provided below.

						$ million
			2012			2011
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	**(43,080)**	**14,067**	**(29,013)**	(44,420)	18,556	(25,864)
Exchange adjustments	**(75)**	**64**	**(11)**	30	(492)	(462)
Net cash flow	**(3,236)**	**5,417**	**2,181**	(4,725)	(3,997)	(8,722)
Movement in finance debt relating to investing activities[b]	**(602)**	**–**	**(602)**	6,167	–	6,167
Other movements	**(104)**	**–**	**(104)**	(132)	–	(132)
At 31 December	**(47,097)**	**19,548**	**(27,549)**	(43,080)	14,067	(29,013)

[a] Including the fair value of associated derivative financial instruments.
[b] See Note 34 for further information.

36. Provisions

$ million

	Decommissioning	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Other	Total
At 1 January 2012	**17,240**	**3,264**	**336**	**10,976**	**3,510**	**2,316**	**37,642**
Exchange adjustments	**261**	**3**	**–**	**–**	**–**	**19**	**283**
Acquisitions	**–**	**–**	**–**	**–**	**–**	**24**	**24**
New or increased provisions	**3,756**	**1,350**	**109**	**6,080**	**–**	**1,260**	**12,555**
Derecognition of provision for items that cannot be reliably estimated	**–**	**–**	**–**	**(794)**	**–**	**–**	**(794)**
Write-back of unused provisions	**–**	**(65)**	**–**	**(50)**	**–**	**(271)**	**(386)**
Unwinding of discount	**107**	**9**	**–**	**18**	**–**	**6**	**140**
Utilization	**(651)**	**(841)**	**(100)**	**(5,979)**	**–**	**(411)**	**(7,982)**
Reclassified as liabilities directly associated with assets held for sale	**(3,048)**	**(91)**	**–**	**–**	**–**	**(11)**	**(3,150)**
Deletions	**(350)**	**(1)**	**–**	**–**	**–**	**(60)**	**(411)**
At 31 December 2012	**17,315**	**3,628**	**345**	**10,251**	**3,510**	**2,872**	**37,921**
Of which – current	**721**	**1,235**	**277**	**4,506**	**–**	**848**	**7,587**
– non-current	**16,594**	**2,393**	**68**	**5,745**	**3,510**	**2,024**	**30,334**

$ million

	Decommissioning	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Other	Total
At 1 January 2011	10,544	2,465	1,043	11,967	3,510	2,378	31,907
Exchange adjustments	(27)	(4)	–	(13)	–	(12)	(56)
Acquisitions	163	–	–	9	–	118	290
New or increased provisions	4,596	1,677	586	3,821	–	1,145	11,825
Write-back of unused provisions	(1)	(140)	–	(92)	–	(416)	(649)
Unwinding of discount	195	27	–	15	–	6	243
Change in discount rate	3,211	90	–	45	–	10	3,356
Utilization	(342)	(840)	(1,293)	(4,715)	–	(876)	(8,066)
Reclassified as liabilities directly associated with assets held for sale	(51)	–	–	–	–	–	(51)
Deletions	(1,048)	(11)	–	(61)	–	(37)	(1,157)
At 31 December 2011	17,240	3,264	336	10,976	3,510	2,316	37,642
Of which – current	596	1,375	282	8,518	–	467	11,238
– non-current	16,644	1,889	54	2,458	3,510	1,849	26,404

Provisions not related to the Gulf of Mexico oil spill

The group makes full provision for the future cost of decommissioning oil and natural gas wells, facilities and related pipelines on a discounted basis upon installation. The provision for the costs of decommissioning these wells, production facilities and pipelines at the end of their economic lives has been estimated using existing technology, at current prices or future assumptions, depending on the expected timing of the activity, and discounted using a real discount rate of 0.5% (2011 0.5%). The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately 20 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 these costs.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be estimated reliably. 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 0.5% (2011 0.5%). The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately five 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 2012 are provisions for deferred employee compensation of $618 million (2011 $666 million). These provisions are discounted using either a nominal discount rate of 2.5% (2011 2.5%) or a real discount rate of 0.5% (2011 0.5%), as appropriate.

36. Provisions continued

Provisions relating to the Gulf of Mexico oil spill

The Gulf of Mexico oil spill is described on pages 59-62 and in Note 2. Provisions relating to the Gulf of Mexico oil spill, included in the table above, are separately presented below:

$ million

	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Total
At 1 January 2012	1,517	336	9,970	3,510	15,333
New or increased provisions – items not covered by the trust funds	48	62	4,773	–	4,883
– items covered by the trust funds	753	47	1,185	–	1,985
Derecognition of provision for items that cannot be reliably estimated	–	–	(794)	–	(794)
Unwinding of discount	1	–	6	–	7
Utilization – paid by BP	(76)	(100)	(1,064)	–	(1,240)
– paid by the trust funds	(381)	–	(4,243)	–	(4,624)
– reclassified to other payables	–	–	(350)	–	(350)
At 31 December 2012	1,862	345	9,483	3,510	15,200
Of which – current	845	277	4,327	–	5,449
– non-current	1,017	68	5,156	3,510	9,751
Of which – payable from the trust funds	1,438	47	4,957	–	6,442

$ million

	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Total
At 1 January 2011	809	1,043	10,973	3,510	16,335
New or increased provisions – items not covered by the trust funds	34	586	525	–	1,145
– items covered by the trust funds	1,133	–	2,905	–	4,038
Unwinding of discount	6	–	–	–	6
Change in discount rate	17	–	–	–	17
Utilization – paid by BP	(33)	(1,293)	(1,175)	–	(2,501)
– paid by the trust funds	(449)	–	(3,258)	–	(3,707)
At 31 December 2011	1,517	336	9,970	3,510	15,333
Of which – current	961	282	8,194	–	9,437
– non-current	556	54	1,776	3,510	5,896
Of which – payable from the trust funds	1,066	–	8,809	–	9,875

As described in Note 2, BP has recorded provisions at 31 December 2012 relating to the Gulf of Mexico oil spill including amounts in relation to environmental expenditure, spill response costs, litigation and claims, and Clean Water Act penalties, each of which is described below. The total amounts that will ultimately be paid by BP are subject to significant uncertainty as described in Note 2 and below.

Environmental

The amounts committed by BP for a 10-year research programme to study the impact of the incident on the marine and shoreline environment of the Gulf of Mexico have been provided for. BP's commitment is to provide $500 million of funding, and the remaining commitment, on a discounted basis, of $376 million was included in provisions at 31 December 2012. This amount is expected to be spent over the remaining life of the programme.

As a responsible party under the Oil Pollution Act of 1990 (OPA 90), BP faces claims by the United States, as well as by State, tribal, and foreign trustees, if any, for natural resource damages ("Natural Resource Damages claims"). These damages include, among other things, the reasonable costs of assessing the injury to natural resources. BP has been incurring natural resource damage assessment costs and a provision has been made for the estimated costs of the assessment phase. Since May 2010, more than 200 initial and amended work plans have been developed to study resources and habitat. The study data will inform an assessment of injury to the Gulf Coast natural resources and the development of a restoration plan to mitigate the identified injuries. Detailed analysis and interpretation continue on the data that have been collected. The expected assessment spend is based upon past experience as well as identified projects. During 2011, BP entered a framework agreement with natural resource trustees for the United States and five Gulf coast states, providing for up to $1 billion to be spent on early restoration projects to address natural resource injuries resulting from the oil spill, to be funded from the $20-billion trust fund. In 2012, work began on the initial set of early restoration projects identified under this framework. The total amount provided for natural resource damage assessment costs and early restoration projects was $1,486 million at 31 December 2012. Until the size, location and duration of the impact is assessed, it is not possible to estimate reliably either the amounts or timing of the remaining Natural Resource Damages claims other than the assessment and early restoration costs noted above, therefore no additional amounts have been provided for these items and they are disclosed as a contingent liability. See Note 43 for further information.

Spill response

Further amounts were provided relating to the spill response during 2012, totalling $0.1 billion (2011 $0.6 billion). By the end of 2012, the US Coast Guard's Federal On-Scene Coordinator (FOSC) had deemed removal actions complete on 4,029 miles of shoreline out of 4,376 miles that were in the area of response. Approximately 108 shoreline miles were pending further monitoring or inspection and a determination that removal actions are complete. The remaining 239 miles are in the patrolling and maintenance phase which will continue until the FOSC determines that operational removal activity is complete.

Litigation and claims

BP faces various claims, principally under OPA 90 but also including under general maritime law, by individuals and businesses for removal costs, damage to real or personal property, lost profits or impairment of earning capacity and loss of subsistence use of natural resources ("Individual and Business Claims") and by state and local government entities for removal costs, physical damage to real or personal property, loss of government revenue and increased public services costs ("State and Local Claims"). BP also faces other litigation related to the Incident brought under US state law

36. Provisions continued

and the laws of certain non-US jurisdictions, as well as claims by private parties under US federal securities laws and other state and federal statutes. See Legal proceedings on pages 162-171 for further information.

The litigation and claims provision includes amounts that can be estimated reliably for the future cost of settling Individual and Business Claims, and State and Local Claims under OPA 90, including certain amounts as set forth below related to the settlements with the PSC, the cost of the agreement with the US government to resolve all federal criminal claims, and claims administration costs and legal fees. During 2012, a provision was recognized in the amount of $525 million in respect of the cost of the agreement with the US Securities and Exchange Commission (SEC) to resolve all of the US government's federal securities claims against the company (the SEC settlement). The remaining obligation for the SEC settlement at 31 December 2012 has been reclassified to other payables (as discussed below).

BP announced on 3 March 2012 that a proposed settlement had been reached with the Plaintiffs' Steering Committee (PSC), subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and property damage claims and exposure-based medical claims (Individual and Business claims) stemming from the Deepwater Horizon accident and oil spill. The PSC acts on behalf of the individual and business plaintiffs in the multi-district litigation proceedings pending in New Orleans (MDL 2179). The proposed settlement was an adjusting event after the 2011 reporting period and BP's estimate at that time of the cost of the settlement of $7.8 billion was therefore reflected in the 2011 financial statements. On 18 April 2012, BP announced that it had reached definitive and fully documented settlement agreements with the PSC consistent with the terms of that settlement. In November 2012, the court held a fairness hearing with respect to the Economic and Property Damages Settlement Agreement and Medical Benefits Settlement Agreement and subsequently granted final approval to the Economic and Property Damages Settlement on 21 December 2012 and to the medical benefits settlement on 11 January 2013. See Legal proceedings on pages 162-171 for further information.

Under the terms of the PSC settlement agreement, several qualified settlement funds (QSFs) were established during the year. These QSFs, which are funded through the Trust, each relate to specific elements of the agreement and are available to make payments to claimants in accordance with those elements of the agreement.

The total amount allocated to the seafood industry under the PSC settlement is fixed at $2.3 billion and thus amounts contributed from the Trust to the seafood compensation fund extinguish BP's liability, so the provision and related reimbursement asset are derecognized, irrespective of whether amounts have been paid out of the fund to claimants. Utilization of the provision in 2012 included $2,230 million contributed to the seafood compensation fund. Additionally, a further $67 million was paid to seafood industry claimants through the transition claims process. At 31 December 2012, $1,847 million remained in the seafood compensation fund for which the related provision and reimbursement asset had been derecognized.

As at 31 December 2011, the provision for items covered by the settlement with the PSC for Individual and Business claims was $7.8 billion. During 2012, BP increased its estimate of the cost of claims administration by $280 million and also increased the provision by a further $400 million as described below.

Business economic loss claims received by the Deepwater Horizon Court Supervised Settlement Program (DHCSSP) to date are being paid at a significantly higher average amount than previously assumed by BP in formulating the original estimate of the cost. Further, BP's initial estimate of aggregate liability under the settlement agreements was premised on BP's interpretation of certain protocols established in the Economic and Property Damages Settlement Agreement. As part of its monitoring of payments made by the DHCSSP, BP identified multiple claim determinations that appeared to result from an interpretation of the settlement agreement by the claims administrator that BP believes was incorrect. This interpretation produced a higher number and value of awards than the interpretation BP assumed in making the initial estimate. Pursuant to the mechanisms in the settlement agreement, the claims administrator sought clarification from the court on this matter and on 30 January 2013, the court initially upheld the claims administrator's interpretation of the agreement.

In its unaudited fourth quarter and full year 2012 results announcement dated 5 February 2013 (the 'preliminary announcement'), BP stated that if the initial trend of higher average payments than assumed by BP in its original estimate of the cost continued, then it was likely that BP's provision for these claims would be increased significantly. Management's initial assessment of the ruling regarding the interpretation of the settlement agreement led to an increase in the estimated cost of the settlement with the PSC of $400 million, bringing the total estimated cost to $8.5 billion. This estimate was based upon management's initial assessment of the ruling's impact on claims already submitted to and processed by the DHCSSP. At that time, BP was seeking reversal of the court's decision in relation to this matter, and management concluded that it was not possible to estimate reliably the impact of the interpretation on any future claims not yet received or processed by the DHCSSP.

On 6 February 2013, the court reconsidered and vacated its ruling of 30 January 2013 and stayed the processing of certain types of business economic loss claims. The court lifted the stay on 28 February 2013. On 5 March 2013, the court affirmed the claims administrator's interpretation of the agreement and rejected BP's position as it relates to business economic loss claims. BP strongly disagrees with the ruling of 5 March 2013 and the current implementation of the agreement by the claims administrator. BP intends to pursue all available legal options including rights of appeal, to challenge this ruling. Other business economic loss claims continue to be paid at a higher average amount than previously assumed by BP in determining its initial estimate of the total cost. Management has continued to analyse the claims in the period since 5 February 2013 to gain a better understanding of whether or not the number and average value of claims received and processed to date are predictive of future claims (and so would allow management to estimate the total cost reliably). Management has concluded, based upon this analysis, that it is not possible to determine whether the claims experience to date is, or is not, an appropriate basis for estimating the total cost. Therefore, given the inherent uncertainty that exists as BP pursues all available legal options to challenge the recent ruling, and the higher number of claims received and higher average claims payments than previously assumed by BP, which may or may not continue, management has concluded that no reliable estimate can be made of any business economic loss claims not yet received or processed by the DHCSSP.

Therefore, the provision for business economic loss claims at 31 December 2012 included in these financial statements now includes only the estimated cost of claims already received and processed by the DHCSSP. As a consequence, an amount of $0.8 billion previously provided for future claims not yet received or processed by the DHCSSP, has been derecognized, with a corresponding reduction in the reimbursement asset and therefore no net impact on the income statement, as no reliable estimate can be made for this liability. It is therefore disclosed as a contingent liability in Note 43. A provision will be re-established when a reliable estimate can be made of the liability as explained more fully below.

BP's current estimate of the total cost of those elements of the PSC settlement that can be estimated reliably, which excludes any future business economic loss claims not yet received or processed by the DHCSSP, is $7.7 billion.

If BP is successful in its challenge to the court's ruling, the total estimated cost of the settlement agreement will, nevertheless, be significantly higher than the current estimate of $7.7 billion because business economic loss claims not yet received or processed are not reflected in the current estimate and the average payments per claim determined so far are higher than anticipated. If BP is not successful in its challenge to the court's ruling, a further significant increase to the total estimated cost of the settlement will be required but BP will continue to challenge the current interpretation and implementation of the settlement agreement by the claims administrator using all legal avenues available, including rights of appeal. However, there can be no certainty as to how the dispute will ultimately be resolved or determined. To the extent that there are insufficient funds available in the Trust fund, payments under the PSC settlement will be made by BP directly and charged to the income statement.

36. Provisions continued

Significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable through the claims process. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported. In addition, there is further uncertainty in relation to interpretations of the claims administrator regarding the protocols under the settlement agreement and judicial interpretation of these protocols, and the outcomes of any further litigation including in relation to potential opt-outs from the settlement or otherwise. The PSC settlement is uncapped except for economic loss claims related to the Gulf seafood industry.

While BP has determined its current best estimate of the cost of those aspects of the settlement with the PSC that can be measured reliably, it is possible that the actual cost of those items could be significantly higher than this estimate due to the uncertainties noted above. In addition, the provision will be re-established for remaining business economic loss claims as more information becomes available, the interpretation of the protocols is clarified and the claims process matures, enabling BP to estimate reliably the cost of these claims. BP will continue to analyse claims data and re-evaluate the assumptions underlying the provision.

The provision recognized for litigation and claims includes an estimate for State and Local government claims. Although the provision recognized is BP's current reliable best estimate of the amount required to settle these obligations, significant uncertainty exists in relation to the outcome of any litigation proceedings and the amount of claims that will become payable by BP. In January 2013, the States of Alabama, Mississippi and Florida formally presented their claims to BP under OPA 90 for alleged losses including economic and property damage as a result of the Gulf of Mexico oil spill (see Note 43 for further information).

BP reached an agreement in November 2012 with the US government, subject to court approval, to resolve all criminal claims arising from the incident under which BP will pay $4 billion in instalments over a period of five years. A provision of $3.85 billion has been recognized, representing the discounted cost of the agreement. This settlement was approved by the court in January 2013 and is not covered by the Trust. In addition, BP reached a settlement with the US Securities and Exchange Commission (SEC), which was approved by the court in December 2012, resolving all of the US government's securities claims against the company, under which BP has agreed to a civil penalty of $525 million, payable in three instalments over a period of three years. On 10 December 2012, a federal judge issued a final judgment regarding the SEC's claims and the terms of the settlement. During 2012, a provision was recognized in the amount of $525 million in respect of the cost of the SEC settlement. The remaining obligation of $350 million for the SEC settlement at 31 December 2012, which is not covered by the trust fund, has been reclassified to other payables.

BP also faces other litigation for which no reliable estimate of the cost can currently be made. Therefore no amounts have been provided for these items. See Note 43 for further information.

Clean Water Act penalties

A provision has been made for the estimated penalties for strict liability under Section 311 of the Clean Water Act. Such penalties are subject to a statutory maximum calculated as the product of a per-barrel maximum penalty rate and the number of barrels of oil spilled. Uncertainties currently exist in relation to both the penalty rate that will ultimately be imposed and the volume of oil spilled.

A charge for potential Clean Water Act Section 311 penalties was first included in BP's second-quarter 2010 interim financial statements. At the time that charge was taken, the latest estimate from the intra-agency Flow Rate Technical Group created by the National Incident Commander in charge of the spill response was between 35,000 and 60,000 barrels per day. The mid-point of that range, 47,500 barrels per day, was used for the purposes of calculating the charge. For the purposes of calculating the amount of the oil flow that was discharged into the Gulf of Mexico, the amount of oil that had been or was projected to be captured in vessels on the surface was subtracted from the total estimated flow up until when the well was capped on 15 July 2010. The result of this calculation was an estimate that approximately 3.2 million barrels of oil had been discharged into the Gulf. This estimate of 3.2 million barrels was calculated using a total flow of 47,500 barrels per day multiplied by the 85 days from 22 April 2010 through 15 July 2010 less an estimate of the amount captured on the surface (approximately 850,000 barrels).

This estimated discharge volume was then multiplied by $1,100 per barrel – the maximum amount the statute allows in the absence of gross negligence or wilful misconduct – for the purposes of estimating a potential penalty. This resulted in a provision of $3,510 million for potential penalties under Section 311.

The actual penalty a court may impose could be lower than $1,100 per barrel if it were determined that such a lower penalty was appropriate based on the factors a court is directed to consider in assessing a penalty. In particular, in determining the amount of a civil penalty, Section 311 directs a court to consider a number of enumerated factors, including "the seriousness of the violation or violations, the economic benefit to the violator, if any, resulting from the violation, the degree of culpability involved, any other penalty for the same incident, any history of prior violations, the nature, extent, and degree of success of any efforts of the violator to minimize or mitigate the effects of the discharge, the economic impact of the penalty on the violator, and any other matters as justice may require." Civil penalties above $1,100 per barrel up to a statutory maximum of $4,300 per barrel of oil discharged would only be imposed if alleged gross negligence or wilful misconduct were proven. BP intends to argue for a penalty lower than $1,100 per barrel based on several of these factors. However, the $1,100 per-barrel rate has been utilized for the purposes of calculating the provision after considering and weighing all possible outcomes and in light of: (i) the company's conclusion that it did not act with gross negligence or engage in wilful misconduct; and (ii) the uncertainty as to whether a court would assess a penalty below the $1,100 statutory maximum.

On 2 August 2010, the United States Department of Energy and the Flow Rate Technical Group had issued an estimate that 4.9 million barrels of oil had flowed from the Macondo well, and 4.05 million barrels had been discharged into the Gulf (the difference being the amount of oil captured by vessels on the surface as part of BP's well containment efforts).

It was and remains BP's view, based on the analysis of available data by its experts, that the 2 August 2010 Government estimate is not reliable. BP believes that the 2 August 2010 discharge estimate is overstated by at least 20%. If the flow rate were 20% lower than the 2 August 2010 estimate, then the amount of oil that flowed from the Macondo well would be approximately 3.9 million barrels and the amount discharged into the Gulf would be approximately 3.1 million barrels (using a current estimate of barrels captured by vessels on the surface of 810,000 in line with the stipulation entered with the US government – see Legal Proceedings on pages 162-171), which is not materially different from the amount we used for our original estimate at the end of the second quarter 2010.

For the purposes of calculating a provision for fines and penalties under Section 311 of the Clean Water Act, BP has continued to use an estimate of 3.2 million barrels of oil discharged to the Gulf of Mexico and a penalty of $1,100 per barrel, as its current best estimate, as defined in paragraphs 36-40 of IAS 37 'Provisions, Contingent Liabilities and Contingent Assets', of the amounts which may be used in calculating the penalty under Section 311 of the Clean Water Act and as a result, the provision at the end of the year was $3,510 million.

The amount and timing of the amount to be paid ultimately will depend upon what is determined by the court in the federal multi-district litigation proceedings in New Orleans (MDL 2179) to be the volume of oil spilled and the penalty rate that is imposed or upon any settlement, if one were to be reached. It is not currently practicable to estimate the timing of expending these costs and the provision has been included within non-current liabilities on the balance sheet. Save in relation to the amounts described in this note, and in Note 2, no other amounts have been provided as at 31 December 2012 in relation to other potential fines and penalties because it is not possible to measure the obligation reliably. Fines and penalties are not covered by the trust fund.

36. Provisions continued

Items not provided for and uncertainties

BP considers that it is not possible, at this time, to measure reliably any obligation in relation to Natural Resource Damages claims under OPA 90 (other than the estimated costs of the assessment phase and the costs of early restoration agreements referred to above). It is also not possible to measure reliably any obligation in relation to business economic loss claims under the PSC settlement not yet received or processed by the DHCSSP, or any other potential litigation (including through excluded parties from the PSC settlement and any obligation in relation to other potential private or governmental litigation), fines, or penalties, other than as described above. These items are therefore disclosed as contingent liabilities – see Note 43 for further information.

The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors. Furthermore, significant uncertainty exists in relation to the amount of claims that will become payable by BP, the amount of fines that will ultimately be levied on BP (including any determination of BP's culpability based on any findings of negligence, gross negligence or wilful misconduct), the outcome of litigation and arbitration proceedings, and any costs arising from any longer-term environmental consequences of the oil spill, which will also impact upon the ultimate cost for BP. The amount and timing of any amounts payable could also be impacted by any further settlements which may or may not occur.

Although the provision recognized is the current best reliable estimate of expenditures required to settle certain present obligations at the end of the reporting period, there are future expenditures for which it is not possible to measure the obligation reliably described further in Note 43.

37. 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. With effect from 1 April 2010, BP closed its UK plan to new joiners other than some of those joining the North Sea business. The plan remains open to ongoing accrual for those employees who had joined BP on or before 31 March 2010. The majority of new joiners in the UK have the option to join a defined contribution plan.

In the US, a range of retirement arrangements is provided. This includes 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 2012, contributions of $884 million (2011 $429 million and 2010 $411 million) and $153 million (2011 $777 million and 2010 $694 million) were made to the UK plans and US plans respectively. In addition, contributions of $238 million (2011 $223 million and 2010 $188 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2013 is expected to be approximately $1,250 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 2012. 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 2011.

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 2012 are used to determine the pension liabilities at that date and the pension expense for 2013.

%

Financial assumptions	UK			US			Other		
	2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Discount rate for pension plan liabilities	**4.4**	4.8	5.5	**3.2**	4.3	4.7	**3.6**	4.7	5.3
Discount rate for other post-retirement benefit plans	**n/a**	n/a	n/a	**3.7**	4.5	5.3	**n/a**	n/a	n/a
Rate of increase in salaries	**4.9**	5.1	5.4	**4.2**	3.7	4.1	**3.7**	3.7	3.8
Rate of increase for pensions in payment	**3.1**	3.2	3.5	**–**	–	–	**1.7**	1.7	1.8
Rate of increase in deferred pensions	**3.1**	3.2	3.5	**–**	–	–	**1.2**	1.2	1.3
Inflation	**3.1**	3.2	3.5	**2.4**	1.9	2.3	**2.2**	2.2	2.3

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.

37. Pensions and other post-retirement benefits continued

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 1.0% depending on country. In addition to the financial assumptions, we regularly review the demographic and mortality assumptions.

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
	2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Life expectancy at age 60 for a male currently aged 60	**27.7**	27.6	26.1	**24.9**	24.8	24.7	**23.6**	23.5	23.3
Life expectancy at age 60 for a male currently aged 40	**30.6**	30.5	29.1	**26.3**	26.3	26.2	**26.5**	26.3	26.2
Life expectancy at age 60 for a female currently aged 60	**29.4**	29.3	28.7	**26.4**	26.4	26.3	**28.2**	28.0	27.9
Life expectancy at age 60 for a female currently aged 40	**32.1**	32.0	31.6	**27.3**	27.3	27.2	**30.8**	30.7	30.6

Our assumption for future US healthcare cost trend rate for the first year after the reporting date reflects the rate of actual cost increases seen in recent years. The ultimate trend rate reflects our long-term expectations of the level at which cost inflation will stabilize based on past healthcare cost inflation seen over a longer period of time. The assumed future US healthcare cost trend rate assumptions are as follows:

			%
	2012	2011	2010
First year's US healthcare cost trend rate	**7.3**	7.6	7.8
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2020**	2020	2018

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	**UK**	**US**	**Other**
Total equity	**73**	**70**	**17-62**
Bonds/cash	**20**	**30**	**25-75**
Property/real estate	**7**	**–**	**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.

Return on asset assumptions at 31 December each year have been used to date in the determination of the pension expense for the following year. However, with effect from 1 January 2013, the group will adopt an amended version of IAS 19 'Employee Benefits', under which the amount credited to the income statement reflecting the return on pension assets will be calculated by applying the discount rate used to measure the obligation, and will therefore be based on a lower corporate bond rate (see Note 1 under Impact of new International Financial Reporting Standards for further information). Under the amended IAS 19, net finance income relating to pensions and other post-retirement benefits, and profit before taxation, would have been approximately $0.8 billion and $0.7 billion lower for 2012 and 2011 respectively, with corresponding pre-tax increases in other comprehensive income. The impact on the group's 2013 profit before taxation is expected to be approximately $1.0 billion. This change has no impact on the balance sheet and no impact on past or expected future cash flows.

The expected long-term rates of return at 31 December 2012 are therefore not presented in the table below. Instead, the table presents the interest rate assumptions at 31 December 2012, which are equal to the discount rate assumptions for plan liabilities as noted above and which will be used in the determination of the pension expense for 2013. For 2011 and 2010, the expected long-term rates of return and market values of the various categories of assets held by the defined benefit plans at 31 December are presented. The market values 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. Movements in the value of plan assets during the year are shown in detail in the table on page 242.

37. Pensions and other post-retirement benefits continued

		2012		2011		2010
	Interest rate	**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[a]		**19,612**	8.0	17,202	8.0	18,546
Bonds		**4,885**	4.4	4,141	5.0	3,866
Property/real estate		**1,783**	6.5	1,710	6.5	1,462
Cash		**1,066**	1.7	534	1.4	406
	4.4	**27,346**	7.0	23,587	7.2	24,280
US pension plans						
Equities[a]		**5,431**	9.0	5,034	9.1	5,058
Bonds		**2,159**	4.0	2,022	4.5	1,419
Property/real estate		**5**	8.0	4	8.0	7
Cash		**191**	0.2	144	0.3	165
	3.2	**7,786**	7.4	7,204	8.0	6,649
US other post-retirement benefit plans						
Cash		**1**	0.2	4	0.3	8
	3.7	**1**	0.2	4	0.3	8
Other plans						
Equities		**940**	7.9	831	8.0	1,182
Bonds		**2,114**	3.3	1,951	4.2	1,874
Property/real estate		**139**	6.2	117	6.3	83
Cash		**340**	2.2	387	2.7	155
	3.6	**3,533**	4.7	3,286	5.4	3,294

[a] The amounts classified as equities include investments in companies listed on stock exchanges as well as private equity investments which are substantially all unlisted. The market value of private equity investments at 31 December 2012 was $4,354 million (2011 $4,099 million and 2010 $3,348 million). The equity return assumption shown above for 2011 and 2010 is the weighted average of the assumed returns for listed and private equity assets in each fund.

The 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 as at 31 December 2012 for the group's plans would have had the effects shown in the table below. The effects shown for the expense in 2013 include current service cost and net finance income or expense.

		$ million
	One percentage point	
	Increase	**Decrease**
Discount rate[a]		
Effect on pension and other post-retirement benefit expense in 2013	**(480)**	**528**
Effect on pension and other post-retirement benefit obligation at 31 December 2012	**(7,364)**	**9,626**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2013	**553**	**(410)**
Effect on pension and other post-retirement benefit obligation at 31 December 2012	**6,986**	**(5,580)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2013	**27**	**(21)**
Effect on US other post-retirement obligation at 31 December 2012	**321**	**(265)**

[a] The amounts presented reflect that from 2013, the discount rate will be used to determine the return on pension assets as well as the interest cost on the obligation, as noted above.

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 2013 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 2013	**39**	**5**	**3**	**8**
Effect on pension and other post-retirement benefit obligation at 31 December 2012	**647**	**118**	**67**	**197**

37. Pensions and other post-retirement benefits continued

					$ million
					2012
	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]	477	328	51	150	1,006
Past service cost	–	20	–	12	32
Settlement, curtailment and special termination benefits	(1)	–	–	71	70
Payments to defined contribution plans	14	223	–	44	281
Total operating charge[b]	490	571	51	277	1,389
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,680	524	–	163	2,367
Interest on plan liabilities	(1,249)	(382)	(134)	(401)	(2,166)
Other finance income (expense)	431	142	(134)	(238)	201
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	989	498	–	164	1,651
Change in assumptions underlying the present value of the plan liabilities	(1,446)	(1,427)	239	(1,130)	(3,764)
Experience gains and losses arising on the plan liabilities	(116)	68	(48)	(126)	(222)
Actuarial (loss) gain recognized in other comprehensive income	(573)	(861)	191	(1,092)	(2,335)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	25,675	8,617	3,061	8,729	46,082
Exchange adjustments	1,313	–	–	251	1,564
Current service cost[a]	477	328	51	150	1,006
Past service cost	–	20	–	12	32
Interest cost	1,249	382	134	401	2,166
Curtailment	(8)	–	–	(15)	(23)
Settlement	–	–	–	1	1
Special termination benefits[c]	7	–	–	85	92
Contributions by plan participants[d]	39	–	–	14	53
Benefit payments (funded plans)[e]	(1,038)	(593)	(3)	(230)	(1,864)
Benefit payments (unfunded plans)[e]	(7)	(84)	(207)	(392)	(690)
Disposals	(10)	–	–	(192)	(202)
Actuarial loss (gain) on obligation	1,562	1,359	(191)	1,256	3,986
Benefit obligation at 31 December[a f]	29,259	10,029	2,845	10,070	52,203
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	23,587	7,204	4	3,286	34,081
Exchange adjustments	1,215	–	–	88	1,303
Expected return on plan assets[a g]	1,680	524	–	163	2,367
Contributions by plan participants[d]	39	–	–	14	53
Contributions by employers (funded plans)	884	153	–	238	1,275
Benefit payments (funded plans)[e]	(1,038)	(593)	(3)	(230)	(1,864)
Disposals	(10)	–	–	(190)	(200)
Actuarial gain on plan assets[g]	989	498	–	164	1,651
Fair value of plan assets at 31 December	27,346	7,786	1	3,533	38,666
Deficit at 31 December	(1,913)	(2,243)	(2,844)	(6,537)	(13,537)
Represented by					
Asset recognized	–	–	–	12	12
Liability recognized	(1,913)	(2,243)	(2,844)	(6,549)	(13,549)
	(1,913)	(2,243)	(2,844)	(6,537)	(13,537)
The deficit may be analysed between funded and unfunded plans as follows					
Funded	(1,688)	(1,599)	(43)	(539)	(3,869)
Unfunded	(225)	(644)	(2,801)	(5,998)	(9,668)
	(1,913)	(2,243)	(2,844)	(6,537)	(13,537)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(29,034)	(9,385)	(44)	(4,072)	(42,535)
Unfunded	(225)	(644)	(2,801)	(5,998)	(9,668)
	(29,259)	(10,029)	(2,845)	(10,070)	(52,203)

[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] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.

[e] The benefit payments amount shown above comprises $2,499 million benefits plus $55 million of plan expenses incurred in the administration of the benefit.

[f] The benefit obligation for other plans includes $4,705 million for the German plan, which is largely unfunded.

[g] 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.

37. Pensions and other post-retirement benefits continued

					$ million
					2011
	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]	383	280	53	133	849
Past service cost	–	184	–	7	191
Settlement, curtailment and special termination benefits	3	–	–	40	43
Payments to defined contribution plans	5	199	–	41	245
Total operating charge[b]	391	663	53	221	1,328
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,799	518	–	185	2,502
Interest on plan liabilities	(1,263)	(369)	(163)	(444)	(2,239)
Other finance income (expense)	536	149	(163)	(259)	263
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	(1,990)	10	(1)	(61)	(2,042)
Change in assumptions underlying the present value of the plan liabilities	(2,680)	(512)	39	(642)	(3,795)
Experience gains and losses arising on the plan liabilities	(84)	(102)	89	(26)	(123)
Actuarial (loss) gain recognized in other comprehensive income	(4,754)	(604)	127	(729)	(5,960)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	22,363	7,988	3,157	8,404	41,912
Exchange adjustments	(137)	–	–	(326)	(463)
Current service cost[a]	383	280	53	133	849
Past service cost	–	184	–	7	191
Interest cost	1,263	369	163	444	2,239
Curtailment	–	–	–	(1)	(1)
Settlement	–	–	–	4	4
Special termination benefits[c]	3	–	–	37	40
Contributions by plan participants[d]	33	–	–	10	43
Benefit payments (funded plans)[e]	(993)	(750)	(3)	(226)	(1,972)
Benefit payments (unfunded plans)[e]	(4)	(68)	(181)	(405)	(658)
Disposals	–	–	–	(20)	(20)
Actuarial loss (gain) on obligation	2,764	614	(128)	668	3,918
Benefit obligation at 31 December[a] [f]	25,675	8,617	3,061	8,729	46,082
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	24,280	6,649	8	3,294	34,231
Exchange adjustments	29	–	–	(123)	(94)
Expected return on plan assets[a] [g]	1,799	518	–	185	2,502
Contributions by plan participants[d]	33	–	–	10	43
Contributions by employers (funded plans)	429	777	–	223	1,429
Benefit payments (funded plans)[e]	(993)	(750)	(3)	(226)	(1,972)
Disposals	–	–	–	(16)	(16)
Actuarial gain (loss) on plan assets[g]	(1,990)	10	(1)	(61)	(2,042)
Fair value of plan assets at 31 December	23,587	7,204	4	3,286	34,081
Deficit at 31 December	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
Represented by					
Asset recognized	–	–	–	17	17
Liability recognized	(2,088)	(1,413)	(3,057)	(5,460)	(12,018)
	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
The deficit may be analysed between funded and unfunded plans as follows					
Funded	(1,852)	(784)	(41)	(492)	(3,169)
Unfunded	(236)	(629)	(3,016)	(4,951)	(8,832)
	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(25,439)	(7,988)	(45)	(3,778)	(37,250)
Unfunded	(236)	(629)	(3,016)	(4,951)	(8,832)
	(25,675)	(8,617)	(3,061)	(8,729)	(46,082)

[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] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.

[e] The benefit payments amount shown above comprises $2,576 million benefits plus $54 million of plan expenses incurred in the administration of the benefit.

[f] The benefit obligation for other plans includes $3,909 million for the German plan, which is largely unfunded.

[g] 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.

37. Pensions and other post-retirement benefits continued

					$ million
					2010
	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]	393	241	48	120	802
Past service cost	–	–	–	3	3
Settlement, curtailment and special termination benefits	24	–	–	161	185
Payments to defined contribution plans	1	187	–	35	223
Total operating charge[b]	418	428	48	319	1,213
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,580	465	1	178	2,224
Interest on plan liabilities	(1,183)	(396)	(169)	(429)	(2,177)
Other finance income (expense)	397	69	(168)	(251)	47
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	1,577	425	(1)	36	2,037
Change in assumptions underlying the present value of the plan liabilities	(1,144)	(498)	(132)	(489)	(2,263)
Experience gains and losses arising on the plan liabilities	12	(167)	(8)	69	(94)
Actuarial (loss) gain recognized in other comprehensive income	445	(240)	(141)	(384)	(320)

[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.

At 31 December 2012, reimbursement balances due from or to other companies in respect of pensions amounted to $732 million reimbursement assets (2011 $546 million) and $15 million reimbursement liabilities (2011 $13 million). These balances are not included as part of the pension surpluses and deficits, but are reflected within other receivables and other payables in the group balance sheet.

					$ million
	2012	2011	2010	2009	2008
History of surplus (deficit) and of experience gains and losses					
Benefit obligation at 31 December	**52,203**	46,082	41,912	40,073	34,847
Fair value of plan assets at 31 December	**38,666**	34,081	34,231	31,453	26,154
Deficit	**(13,537)**	(12,001)	(7,681)	(8,620)	(8,693)
Experience losses on plan liabilities	**(222)**	(123)	(94)	(421)	(178)
Actual return less expected return on pension plan assets	**1,651**	(2,042)	2,037	2,549	(10,253)
Actual return on plan assets	**4,018**	460	4,261	4,528	(7,331)
Actuarial loss recognized in other comprehensive income	**(2,335)**	(5,960)	(320)	(682)	(8,430)
Cumulative amount recognized in other comprehensive income	**(12,237)**	(9,902)	(3,942)	(3,622)	(2,940)

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2022 are as follows:

					$ million
	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
2013	**1,115**	**813**	**167**	**560**	**2,655**
2014	**1,163**	**829**	**169**	**568**	**2,729**
2015	**1,211**	**847**	**171**	**567**	**2,796**
2016	**1,268**	**851**	**173**	**561**	**2,853**
2017	**1,276**	**849**	**173**	**554**	**2,852**
2018-2022	**7,059**	**4,003**	**851**	**2,659**	**14,572**

38. Called-up share capital

The allotted, called up and fully paid share capital at 31 December was as follows:

	2012		2011		2010	
Issued	**Shares thousand**	**$ million**	Shares thousand	$ million	Shares thousand	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,813,410**	**5,203**	20,647,160	5,162	20,629,665	5,158
Issue of new shares for the scrip dividend programme	**138,406**	**35**	165,601	41	–	–
Issue of new shares for employee share-based payment plans[b]	**7,343**	**2**	649	–	17,495	4
At 31 December	**20,959,159**	**5,240**	20,813,410	5,203	20,647,160	5,162
		5,261		5,224		5,183

[a] The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.

[b] The nominal value of new shares issued for the employee share plans in 2011 amounted to $162,000. Consideration received relating to the issue of new shares for employee share plans amounted to $47 million (2011 $4 million and 2010 $138 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

	2012		2011		2010	
	Shares thousand	**Nominal value $ million**	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,837,508**	**459**	1,850,699	462	1,869,777	467
Shares transferred to ESOPs at market price	**–**	**–**	–	–	(7,125)	(2)
Shares re-issued for employee share-based payment plans	**(14,100)**	**(4)**	(13,191)	(3)	(11,953)	(3)
At 31 December	**1,823,408**	**455**	1,837,508	459	1,850,699	462

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 8.8% (2011 9.0% and 2010 9.1%) of the called-up ordinary share capital of the company.

During 2012, the movement in treasury shares represented less than 0.1% (2011 less than 0.1% and 2010 less than 0.1%) of the ordinary share capital of the company.

39. Capital and reserves

	Share capital	**Share premium account**	**Capital redemption reserve**	**Merger reserve**	**Total share capital and capital reserves**
At 1 January 2012	**5,224**	**9,952**	**1,072**	**27,206**	**43,454**
Currency translation differences (including recycling)	**–**	**–**	**–**	**–**	**–**
Actuarial loss relating to pensions and other post-retirement benefits	**–**	**–**	**–**	**–**	**–**
Available-for-sale investments (including recycling)	**–**	**–**	**–**	**–**	**–**
Cash flow hedges (including recycling)	**–**	**–**	**–**	**–**	**–**
Share of equity-accounted entities' other comprehensive income, net of tax	**–**	**–**	**–**	**–**	**–**
Other	**–**	**–**	**–**	**–**	**–**
Profit for the year	**–**	**–**	**–**	**–**	**–**
Total comprehensive income	**–**	**–**	**–**	**–**	**–**
Dividends	**35**	**(35)**	**–**	**–**	**–**
Share-based payments[a]	**2**	**57**	**–**	**–**	**59**
Transactions involving minority interests	**–**	**–**	**–**	**–**	**–**
At 31 December 2012	**5,261**	**9,974**	**1,072**	**27,206**	**43,513**

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2011	5,183	9,987	1,072	27,206	43,448
Currency translation differences (including recycling)	–	–	–	–	–
Actuarial loss relating to pensions and other post-retirement benefits	–	–	–	–	–
Available-for-sale investments (including recycling)	–	–	–	–	–
Cash flow hedges (including recycling)	–	–	–	–	–
Share of equity-accounted entities' other comprehensive income, net of tax	–	–	–	–	–
Profit for the year	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	41	(41)	–	–	–
Share-based payments[a]	–	6	–	–	6
Transactions involving minority interests	–	–	–	–	–
At 31 December 2011	5,224	9,952	1,072	27,206	43,454

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2010	5,179	9,847	1,072	27,206	43,304
Currency translation differences (including recycling)	–	–	–	–	–
Actuarial loss relating to pensions and other post-retirement benefits	–	–	–	–	–
Available-for-sale investments (including recycling)	–	–	–	–	–
Cash flow hedges (including recycling)	–	–	–	–	–
Profit (loss) for the year	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	–	–	–	–	–
Share-based payments[a]	4	140	–	–	144
Transactions involving minority interests	–	–	–	–	–
At 31 December 2010	5,183	9,987	1,072	27,206	43,448

[a] Includes new share issues and movements in own shares and treasury shares where these relate to employee share-based payment plans.

$ million

Own shares	**Treasury shares**	**Total own shares and treasury shares**	**Foreign currency translation reserve**	**Available-for-sale investments**	**Cash flow hedges**	**Total fair value reserves**	**Share-based payment reserve**	**Profit and loss account**	**BP shareholders' equity**	**Minority interest**	**Total equity**
(388)	**(20,935)**	**(21,323)**	**4,422**	**389**	**(122)**	**267**	**1,582**	**83,063**	**111,465**	**1,017**	**112,482**
–	**–**	**–**	**665**	**–**	**(5)**	**(5)**	**–**	**–**	**660**	**2**	**662**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(1,721)**	**(1,721)**	**2**	**(1,719)**
–	**–**	**–**	**–**	**296**	**–**	**296**	**–**	**–**	**296**	**–**	**296**
–	**–**	**–**	**–**	**–**	**1,217**	**1,217**	**–**	**–**	**1,217**	**–**	**1,217**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(98)**	**(98)**	**–**	**(98)**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**23**	**23**	**–**	**23**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**11,582**	**11,582**	**234**	**11,816**
–	**–**	**–**	**665**	**296**	**1,212**	**1,508**	**–**	**9,786**	**11,959**	**238**	**12,197**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(5,294)**	**(5,294)**	**(82)**	**(5,376)**
108	**161**	**269**	**–**	**–**	**–**	**–**	**26**	**(70)**	**284**	**–**	**284**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**33**	**33**
(280)	**(20,774)**	**(21,054)**	**5,087**	**685**	**1,090**	**1,775**	**1,608**	**87,485**	**118,414**	**1,206**	**119,620**

Own shares	Treasury shares	Total own shares and treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
(126)	(21,085)	(21,211)	4,937	463	6	469	1,586	65,758	94,987	904	95,891
–	–	–	(515)	–	(1)	(1)	–	–	(516)	(10)	(526)
–	–	–	–	–	–	–	–	(4,321)	(4,321)	(3)	(4,324)
–	–	–	–	(74)	–	(74)	–	–	(74)	–	(74)
–	–	–	–	–	(127)	(127)	–	–	(127)	–	(127)
–	–	–	–	–	–	–	–	(57)	(57)	–	(57)
–	–	–	–	–	–	–	–	25,700	25,700	397	26,097
–	–	–	(515)	(74)	(128)	(202)	–	21,322	20,605	384	20,989
–	–	–	–	–	–	–	–	(4,072)	(4,072)	(245)	(4,317)
(262)	150	(112)	–	–	–	–	(4)	102	(8)	–	(8)
–	–	–	–	–	–	–	–	(47)	(47)	(26)	(73)
(388)	(20,935)	(21,323)	4,422	389	(122)	267	1,582	83,063	111,465	1,017	112,482

Own shares	Treasury shares	Total own shares and treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
(214)	(21,303)	(21,517)	4,811	754	22	776	1,584	72,655	101,613	500	102,113
–	–	–	126	–	2	2	–	–	128	3	131
–	–	–	–	–	–	–	–	(418)	(418)	–	(418)
–	–	–	–	(291)	–	(291)	–	–	(291)	–	(291)
–	–	–	–	–	(18)	(18)	–	–	(18)	–	(18)
–	–	–	–	–	–	–	–	(3,719)	(3,719)	395	(3,324)
–	–	–	126	(291)	(16)	(307)	–	(4,137)	(4,318)	398	(3,920)
–	–	–	–	–	–	–	–	(2,627)	(2,627)	(315)	(2,942)
88	218	306	–	–	–	–	2	(113)	339	–	339
–	–	–	–	–	–	–	–	(20)	(20)	321	301
(126)	(21,085)	(21,211)	4,937	463	6	469	1,586	65,758	94,987	904	95,891

39. 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.

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. 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 ESOPs vest unconditionally to employees, the amount paid for those shares is shown as a reduction in shareholders' equity. Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2012, the ESOPs held 22,428,179 shares (2011 27,784,503 shares and 2010 11,477,253 shares) for potential future awards, which had a market value of $154 million (2011 $197 million and 2010 $82 million). At 31 December 2012, a further 18,673,926 ordinary share equivalents (2011 21,420,000 ordinary share equivalents) were held by the group in the form of ADSs to meet the requirements of employee share-based payment plans in the US.

Treasury shares

Treasury shares represent BP shares repurchased and available for re-issue.

Foreign currency translation reserve

The foreign currency translation reserve records 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.

Available-for-sale investments

This reserve records the changes in fair value of available-for-sale investments. On disposal or impairment of the investments, 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. For further information see Note 1.

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.

39. 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
			2012
	Pre-tax	**Tax**	**Net of tax**
Currency translation differences (including recycling)	**516**	**146**	**662**
Actuarial loss relating to pensions and other post-retirement benefits	**(2,335)**	**616**	**(1,719)**
Available-for-sale investments (including recycling)	**305**	**(9)**	**296**
Cash flow hedges (including recycling)	**1,547**	**(330)**	**1,217**
Share of equity-accounted entities' other comprehensive income	**(98)**	**–**	**(98)**
Other	**–**	**23**	**23**
Other comprehensive income	**(65)**	**446**	**381**

			$ million
			2011
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	(512)	(14)	(526)
Actuarial loss relating to pensions and other post-retirement benefits	(5,960)	1,636	(4,324)
Available-for-sale investments (including recycling)	(74)	–	(74)
Cash flow hedges (including recycling)	(164)	37	(127)
Share of equity-accounted entities' other comprehensive income	(57)	–	(57)
Other comprehensive income	(6,767)	1,659	(5,108)

			$ million
			2010
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	239	(108)	131
Actuarial loss relating to pensions and other post-retirement benefits	(320)	(98)	(418)
Available-for-sale investments (including recycling)	(341)	50	(291)
Cash flow hedges (including recycling)	(37)	19	(18)
Other comprehensive income	(459)	(137)	(596)

40. Share-based payments

Effect of share-based payment transactions on the group's result and financial position

			$ million
	2012	2011	2010
Total expense recognized for equity-settled share-based payment transactions	**669**	579	577
Total expense (credit) recognized for cash-settled share-based payment transactions	**5**	5	(1)
Total expense recognized for share-based payment transactions	**674**	584	576
Closing balance of liability for cash-settled share-based payment transactions	**12**	12	16
Total intrinsic value for vested cash-settled share-based payments	**–**	1	1

All share-based payment transactions relate to employee compensation.

For ease of presentation, options and share units detailed in the tables within this note are stated as UK ordinary share equivalents in US dollars. US employees are granted options or share units over the company's American Depositary Shares (ADSs) (one ADS is equivalent to six ordinary shares). The main share-based payment plans that existed during the year are detailed below.

Plans for executive directors

For information on the Executive Directors' Incentive Plan (EDIP) see the Directors' remuneration report on pages 127-145.

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 other 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 will normally preclude the conversion of units into shares, but special arrangements apply for participants that leave for qualifying reasons. 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 related to the level of seniority of employees and country of operation. The number of units converted to shares is determined by reference to performance measures over the three-year performance period. Performance measures used include BP's total shareholder return (TSR) compared with the other oil majors, balanced scorecard and individual rating. The relative weighting of these different measures is related to the level of seniority of the employee. Plans included in this category are the Competitive Performance Plan (CPP) (no further grants to be made under this plan after 2011) and the Share Value Plan (SVP).

40. Share-based payments continued

Restricted share unit plans

Share unit grants under the Restricted Share Plan (RSP) are used in special circumstances such as recruitment and retention of senior employees and normally have no performance conditions.

Share unit grants under BP's other restricted share 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 potential. Plans included in this category are the Executive Performance Plan (EPP), the Performance Share Plan (PSP) (no further grants to be made under these plans after 2011) and the Deferred Annual Bonus Plan (DAB).

BP Share Option Plan (BPSOP)

Share options with an exercise price equivalent to the closing market price of a BP share immediately preceding the date of grant were granted to participants annually until 2006. These options are not subject to any performance conditions and are exercisable between the third and tenth anniversaries of the grant date.

BP Plan 2011

Share options with an exercise price equivalent to the closing market price of a BP share immediately preceding the date of grant were granted to participants in 2011. These options are not subject to any performance conditions and will be exercisable between the third and tenth anniversaries of the grant date, with special arrangements applying to participants who leave employment for qualifying reasons.

Matching and saving plans

BP ShareMatch plans

These matching share plans give employees the opportunity to buy ordinary shares in BP p.l.c. and receive free matching shares in BP p.l.c., up to a predetermined limit. The plans are run in the UK and in more than 50 other countries.

BP ShareSave Plan

This plan is open to all eligible UK employees. Participants can contribute up to a maximum of £250 per month from their net salary to a savings account over a three- or five-year contractual savings period. At the end of the savings period, they are entitled to purchase shares in BP p.l.c. at a preset price determined on the date when the invitations are sent to eligible employees. This price is usually set at a discount to the market price of a share of up to 20%.

Local plans

In some countries, BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances. Certain US employees may participate in a defined contribution (401k) plan in which BP matches employee contributions up to certain limits. Participants may invest in several investment options including a BP Stock Fund that holds BP ADSs and a small percentage of cash.

Share option transactions

Details of share option transactions for the year under the share option plans are as follows:

	2012		2011		2010	
Share option transactions	**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	**374,500,712**	**7.73**	263,306,722	8.75	295,895,357	8.73
Granted[a]	**17,651,908**	**5.01**	152,472,556	6.03	10,420,287	6.08
Forfeited	**(17,501,294)**	**6.55**	(9,058,406)	7.22	(9,499,661)	7.88
Exercised	**(11,588,295)**	**6.46**	(2,502,306)	7.64	(31,839,034)	7.97
Expired	**(38,966,978)**	**8.29**	(29,717,854)	8.26	(1,670,227)	8.71
Outstanding at 31 December[b]	**324,096,053**	**7.62**	374,500,712	7.73	263,306,722	8.75
Exercisable at 31 December	**159,419,041**	**9.33**	209,776,014	9.01	242,530,635	8.90

[a] Share options granted during 2011 include 142.5 million options awarded under the BP Plan 2011 with a fair value of $1.02 per option at the date of grant, determined using a binomial option pricing model including assumptions for share price volatility, dividends, and cancellations.

[b] Share options outstanding at 31 December 2012 include 158 million options granted under the BPSOP (2011 208 million options and 2010 239 million options).

The weighted average share price at the date of exercise was $7.20 (2011 $7.71 and 2010 $9.54).

For options outstanding at 31 December 2012, the exercise price ranges and weighted average remaining contractual lives were as 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 $**
$5.01 – $6.73	**183,757,213**	**6.77**	**5.96**	**26,176,779**	**6.35**
$6.74 – $8.45	**49,881,487**	**2.08**	**7.83**	**43,881,487**	**7.94**
$8.46 – $10.18	**19,099,639**	**1.93**	**9.89**	**18,237,061**	**9.93**
$10.19 – $11.92	**71,357,714**	**2.80**	**11.13**	**71,123,714**	**11.13**
	324,096,053	**4.89**	**7.62**	**159,419,041**	**9.33**

At 31 December 2012 the quoted value of one BP ordinary share was $6.86.

40. Share-based payments continued

Fair values and associated details for share units granted

For share units granted in 2012, the number of units and weighted average fair value at the date of grant were as shown below:

Share units granted in 2012	SVP TSR	SVP non-TSR	RSP	DAB
Number of share units granted (million)	**0.5**	**60.3**	**11.2**	**19.6**
Weighted average fair value	**$8.96**	**$7.78**	**$7.21**	**$7.78**
Fair value measurement basis	**Monte Carlo**	**Market value**	**Market value**	**Market value**

Share units granted in 2011	CPP	EPP	RSP	DAB	PSP
Number of share units granted (million)	1.4	8.9	20.0	17.5	19.2
Weighted average fair value	$11.99	$7.51	$6.86	$7.51	$7.51
Fair value measurement basis	Monte Carlo	Market value	Market value	Market value	Market value

Share units granted in 2010	CPP	EPP	RSP	DAB	PSP
Number of share units granted (million)	1.3	7.6	21.4	24.5	16.0
Weighted average fair value	$19.81	$9.43	$6.78	$9.43	$9.43
Fair value measurement basis	Monte Carlo	Market value	Market value	Market value	Market value

The group uses the observable market price for ordinary shares at the date of grant to determine the fair value of non-TSR share unit awards.

The group used a Monte Carlo simulation to determine the fair values of the TSR elements of the 2012 SVP grant, the 2012, 2011 and 2010 EDIP grants and the 2011 and 2010 CPP grants. In accordance with the plans' rules, the model simulates BP's TSR and compares it against its principal strategic competitors over the three-year period of the plans. The model takes into account the historical 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 intended value of share-based payments made to recipients, which are determined by the remuneration committee according to established criteria.

41. Employee costs and numbers

			$ million
Employee costs	**2012**	2011	2010
Wages and salaries[a]	**10,357**	9,827	9,242
Social security costs	**898**	851	789
Share-based payments	**674**	584	576
Pension and other post-retirement benefit costs	**1,188**	1,065	1,166
	13,117	12,327	11,773

Number of employees at 31 December[b]	**2012**	2011	2010
Upstream	**24,000**	22,200	21,100
Downstream[c]	**51,300**	51,000	52,300
Other businesses and corporate	**10,300**	10,100	6,200
Gulf Coast Restoration Organization	**100**	100	100
	85,700	83,400	79,700
By geographical area			
US	**23,400**	22,900	22,100
Non-US[c]	**62,300**	60,500	57,600
	85,700	83,400	79,700

			2012			2011			2010
Average number of employees[b]	**US**	**Non-US**	**Total**	US	Non-US	Total	US	Non-US	Total
Upstream	**9,300**	**13,900**	**23,200**	8,500	13,200	21,700	8,100	13,500	21,600
Downstream	**12,000**	**39,400**	**51,400**	12,300	39,200	51,500	12,600	38,300	50,900
Other businesses and corporate	**1,900**	**8,700**	**10,600**	1,700	6,500	8,200	1,900	5,000	6,900
Gulf Coast Restoration Organization	**100**	**–**	**100**	100	–	100	–	–	–
	23,300	**62,000**	**85,300**	22,600	58,900	81,500	22,600	56,800	79,400

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[a] Includes termination payments of $77 million (2011 $126 million and 2010 $166 million).

[b] Reported to the nearest 100.

[c] Includes 14,700 (2011 14,600 and 2010 15,200) service station staff.

42. Remuneration of directors and senior management

Remuneration of directors

			$ million
	2012	2011	2010
Total for all directors			
Emoluments	**12**	10	15
Gains made on exercise of share options	**–**	–	2
Amounts awarded under incentive schemes	**3**	1	4
Total	**15**	11	21

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 cash bonuses awarded for the year. There was no compensation for loss of office in 2012 (2011 nil and 2010 $3 million).

Pension contributions

During 2012 two 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 2012.

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 127-145.

Remuneration of directors and senior management

			$ million
Total for all senior management	**2012**	2011	2010
Total for all senior management			
Short-term employee benefits	**27**	34	25
Pensions and other post-retirement benefits	**3**	3	3
Share-based payments	**34**	27	29
Total	**64**	64	57

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. There was no compensation for loss of office paid in 2012 (2011 $9 million and 2010 $3 million).

Pensions and other 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, DAB, SVP and RSP. For details of these plans refer to Note 40.

43. Contingent liabilities

Contingent liabilities relating to the Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill, as described on pages 59-62, BP has incurred costs during the year and recognized provisions for certain future costs. Further information is provided in Note 2 and Note 36.

BP has provided for its best estimate of amounts expected to be paid from the $20-billion trust fund. This includes certain amounts expected to be paid pursuant to the Oil Pollution Act of 1990 (OPA 90) as described in Note 36. It is not possible, at this time, to measure reliably other obligations arising from the accident that are under the terms of the trust fund, namely any obligation in relation to Natural Resource Damages claims (except for the estimated costs of the assessment phase and the costs relating to early restoration agreements as described in Note 36), claims asserted in civil litigation including any further litigation through excluded parties from the PSC settlement, the cost of business economic loss claims under the PSC settlement not yet received or processed by the Deepwater Horizon Court Supervised Settlement Program (DHCSSP), any further obligation that may arise from state and local government presentment claims under OPA 90 and any obligation in relation to other potential private or governmental litigation, nor is it practicable to estimate their magnitude or possible timing of payment. Therefore, no amounts have been provided for these obligations as at 31 December 2012. The $20-billion trust fund may not be sufficient to satisfy all claims under OPA 90 or otherwise that will ultimately be paid.

Natural resource damages resulting from the oil spill are currently being assessed (see Note 36 for further information). BP and the federal and state trustees are collecting extensive data in order to assess the extent of damage to wildlife, shoreline, near shore and deepwater habitats, and recreational uses, among other things. The study data will inform an assessment of injury to the Gulf Coast natural resources and the development of a restoration plan to mitigate the identified injuries. Detailed analysis and interpretation continue on the data that have been collected. Any early restoration projects undertaken pursuant to the $1-billion framework agreement could mitigate the total damages resulting from the incident. Accordingly, until the size, location and duration of the impact is assessed, it is not possible to estimate reliably either the amounts or timing of the remaining Natural Resource Damages claims, therefore no amounts have been provided as at 31 December 2012.

As set out more fully in Note 36, business economic loss claims received by the DHCSSP to date are being paid at a significantly higher average amount than previously assumed by BP. Further, BP has identified multiple business economic loss claim determinations under the PSC settlement that appeared to result from an interpretation of the Economic and Property Damages Settlement Agreement by the claims administrator that BP believes was incorrect. This interpretation produced a higher number and value of awards than the interpretation BP assumed in making the initial estimate of the cost of the settlement. Pursuant to the mechanisms in the settlement agreement, the claims administrator sought clarification from the court on this matter and on 30 January 2013, the court initially upheld the claims administrator's interpretation of the agreement. On 6 February 2013, the court reconsidered and vacated this ruling and stayed the processing of certain types of claims. The court lifted the stay on 28 February 2013. On 5 March 2013, the court affirmed the claims administrator's interpretation of the agreement and rejected BP's position as it relates to business economic loss claims. BP strongly disagrees with the ruling of 5 March 2013 and the current implementation of the agreement by the claims administrator. BP intends to pursue all available legal options, including rights of appeal, to challenge this ruling. Management has concluded that it is not possible to determine whether the claims experience to date is, or is not, an appropriate basis for estimating the total cost. Therefore given the inherent uncertainty that exists as BP pursues all available legal options to challenge the ruling, including rights of appeal to challenge the decision, and the higher number of claims received and higher average claims payments than previously assumed by BP, which may or may not continue, management has concluded that no reliable estimate can be made of any business economic loss claims not yet received or processed by the DHCSSP. Therefore the potential cost of such claims is not provided for and is disclosed as a contingent liability. See Note 36 for further information.

In January 2013, the States of Alabama, Mississippi and Florida formally presented their claims to BP under OPA 90 for alleged losses including economic and property damage as a result of the Gulf of Mexico oil spill. BP is evaluating these claims. The State of Louisiana has also asserted similar claims. The amounts claimed, certain of which include punitive damages or other multipliers, are very substantial. However BP considers the methodologies used to calculate these claims to be seriously flawed, not supported by the legislation and to substantially overstate the claims. Claims have also been presented by various local governments which are substantial in aggregate and more claims are expected to be presented. The amounts alleged in the presentments for State and Local government claims total over $34 billion. BP will defend vigorously against these claims if adjudicated at trial.

BP is named as a defendant in approximately 750 civil lawsuits brought by individuals, businesses, insurers and government entities in US federal and state courts, as well as certain foreign jurisdictions, resulting from the Deepwater Horizon accident, the Gulf of Mexico oil spill, and the spill response efforts. Further actions are likely to be brought. Among other claims, these lawsuits assert claims for personal injury or wrongful death in connection with the accident and the spill response, commercial and economic injury, damage to real and personal property, breach of contract and violations of statutes, including, but not limited, to alleged violations of US securities and environmental statutes. Until further fact and expert disclosures occur, court rulings clarify the issues in dispute, liability and damage trial activity nears or progresses, or other actions such as further possible settlements occur, it is not possible given these uncertainties to arrive at a range of outcomes or a reliable estimate of the liabilities that may accrue to BP in connection with or as a result of these claims. Therefore no amounts have been provided for these items as at 31 December 2012. See Legal proceedings on pages 162-171 for further information.

For those items not covered by the trust fund it is not possible to measure reliably any obligation in relation to other litigation or potential fines and penalties except, subject to certain assumptions detailed in Note 36, for those relating to the Clean Water Act. There are a number of federal and state environmental and other provisions of law, other than the Clean Water Act, under which one or more governmental agencies could seek civil fines and penalties from BP. For example, a complaint filed by the United States sought to reserve the ability to seek penalties and other relief under a number of other laws. Given the large number of claims that may be asserted, it is not possible at this time to determine whether and to what extent any such claims would be successful or what penalties or fines would be assessed. Therefore no amounts have been provided for these items.

Under the settlement agreements with Anadarko and MOEX, and with Cameron International, the designer and manufacturer of the Deepwater Horizon blowout preventer, with M-I L.L.C. (M-I), the mud contractor, and with Weatherford, the designer and manufacturer of the float collar used on the Macondo well, BP has agreed to indemnify Anadarko, MOEX, Cameron, M-I and Weatherford for certain claims arising from the accident. It is therefore possible that BP may face claims under these indemnities, but it is not currently possible to reliably measure any obligation in relation to such claims and therefore no amount has been provided as at 31 December 2012.

The magnitude and timing of possible obligations in relation to the Gulf of Mexico oil spill are subject to a very high degree of uncertainty as described further in Risk factors on pages 38-44. Furthermore, for those items for which a provision has been recorded, as noted in Note 36, significant uncertainty also exists in relation to the ultimate exposure and cost to BP. Any such possible obligations are therefore contingent liabilities and, at present, it is not practicable to estimate their magnitude or possible timing of payment. Furthermore, other material unanticipated obligations may arise in future in relation to the incident.

43. Contingent liabilities continued

Other contingent liabilities

There were contingent liabilities at 31 December 2012 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 26.

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.

44. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2012 amounted to $14,068 million (2011 $12,517 million). In addition, at 31 December 2012, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $275 million (2011 $296 million) and investments in associates of nil (2011 $36 million). BP's share of capital commitments of jointly controlled entities amounted to $825 million (2011 $1,244 million). The group has also signed definitive and binding sale and purchase agreements for the sale of BP's 50% interest in TNK-BP to Rosneft and for BP's further investment in Rosneft, as described in Note 4.

45. Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2012 and the group percentage of ordinary share capital or joint venture interest (to nearest whole number) are set out below. 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 & Wales	Investment holding
BP Europa	100	Germany	Refining and marketing and petrochemicals
BP Exploration Operating Company	100	England & Wales	Exploration and production
*BP Global Investments	100	England & Wales	Investment holding
*BP International	100	England & Wales	Integrated oil operations
BP Oil International	100	England & Wales	Integrated oil operations
*BP Shipping	100	England & Wales	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 & Wales	Exploration and production
Australia			
BP Australia Capital Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
BP Oil Australia	100	Australia	Integrated oil operations
Azerbaijan			
BP Exploration (Caspian Sea)	100	England & Wales	Exploration and production
Brazil			
BP Energy do Brazil	100	Brazil	Exploration and production
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Company	100	US	Exploration and production
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
Indonesia			
BP Berau	100	US	Exploration and production
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
South Africa			
*BP Southern Africa	75	South Africa	Refining and marketing
Trinidad & Tobago			
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England & Wales	Finance
BP Oil UK	100	England & Wales	Marketing
Britoil	100	Scotland	Exploration and production
US			
*BP Holdings North America	100	England & Wales	Investment holding
Atlantic Richfield Company	100	US	Exploration and production, refining and marketing, pipelines and petrochemicals
BP America	100	US	
BP America Production Company	100	US	
BP Amoco Chemical Company	100	US	
BP Company North America	100	US	
BP Corporation North America	100	US	
BP Exploration & Production	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
BP West Coast Products	100	US	
Standard Oil Company	100	US	
BP Capital Markets America	100	US	Finance

45. Subsidiaries, jointly controlled entities and associates continued

Jointly controlled entities	%	Country of incorporation	Principal activities
Angola			
Angola LNG Supply Services	14	US	LNG processing and transportation
Argentina			
Pan American Energy[a]	60	US	Exploration and production
Canada			
Sunrise Oil Sands	50	Canada	Exploration and production
China			
Shanghai SECCO Petrochemical Company	50	China	Petrochemicals
Germany			
Ruhr Oel	50	Germany	Refining and petrochemicals
Trinidad & Tobago			
Atlantic 4 Holdings	38	US	LNG manufacture
Atlantic LNG 2/3 Company of Trinidad and Tobago	43	Trinidad & Tobago	LNG manufacture
UK			
Vivergo Fuels	46	England & Wales	Biofuels
US			
BP-Husky Refining	50	US	Refining
Flat Ridge 2 Wind Holdings	50	US	Power generation
Watson Cogeneration[ab]	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.

[b] As at 31 December 2012, the group's interests in Watson Cogeneration have been classified as assets held for sale.

Associates	%	Country of incorporation	Principal activities
Abu Dhabi			
Abu Dhabi Gas Liquefaction Company	10	United Arab Emirates	Crude oil production
Abu Dhabi Marine Areas	33	England & Wales	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Company	30	Cayman Islands	Pipelines
South Caucasus Pipeline Company	26	Cayman Islands	Pipelines
Russia			
TNK-BP[c]	50	British Virgin Islands	Integrated oil operations

[c] As at 31 December 2012, the group's interests in TNK-BP have been classified as assets held for sale. See Note 4 for further information.

46. 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 accounted 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.

46. Condensed consolidating information on certain US subsidiaries continued

Income statement

$ million

For the year ended 31 December	Issuer	Guarantor			2012
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	5,501	–	375,580	(5,501)	375,580
Earnings from jointly controlled entities – after interest and tax	–	–	744	–	744
Earnings from associates – after interest and tax	–	–	3,675	–	3,675
Equity-accounted income of subsidiaries – after interest and tax	(59)	12,775	–	(12,716)	–
Interest and other revenues	12	187	1,677	(286)	1,590
Gains on sale of businesses and fixed assets	3,580	–	6,696	(3,580)	6,696
Total revenues and other income	9,034	12,962	388,372	(22,083)	388,285
Purchases	777	–	297,966	(5,501)	293,242
Production and manufacturing expenses	1,475	–	32,436	–	33,911
Production and similar taxes	1,374	–	6,784	–	8,158
Depreciation, depletion and amortization	457	–	12,024	–	12,481
Impairment and losses on sale of businesses and fixed assets	957	–	5,318	–	6,275
Exploration expense	–	–	1,475	–	1,475
Distribution and administration expenses	35	1,766	11,641	(85)	13,357
Fair value gain on embedded derivatives	–	–	(347)	–	(347)
Profit before interest and taxation	3,959	11,196	21,075	(16,497)	19,733
Finance costs	48	43	1,235	(201)	1,125
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(431)	230	–	(201)
Profit before taxation	3,911	11,584	19,610	(16,296)	18,809
Taxation	203	2	6,788	–	6,993
Profit for the year	3,708	11,582	12,822	(16,296)	11,816
Attributable to					
BP shareholders	3,708	11,582	12,588	(16,296)	11,582
Minority interest	–	–	234	–	234
	3,708	11,582	12,822	(16,296)	11,816

Statement of comprehensive income

$ million

For the year ended 31 December	Issuer	Guarantor			2012
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	3,708	11,582	12,822	(16,296)	11,816
Currency translation differences	–	(98)	629	–	531
Exchange (gains) or losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	–	–	(15)	–	(15)
Actuarial loss relating to pensions and other post-retirement benefits	–	(573)	(1,762)	–	(2,335)
Available-for-sale investments marked to market	–	–	306	–	306
Available-for-sale – recycled to the income statement	–	–	(1)	–	(1)
Cash flow hedges marked to market	–	–	1,466	–	1,466
Cash flow hedges – recycled to the income statement	–	–	62	–	62
Cash flow hedges – recycled to the balance sheet	–	–	19	–	19
Share of equity-accounted entities' other comprehensive income, net of tax	–	–	(98)	–	(98)
Taxation	–	–	446	–	446
Other comprehensive income	–	(671)	1,052	–	381
Total comprehensive income	3,708	10,911	13,874	(16,296)	12,197
Attributable to					
BP shareholders	3,708	10,911	13,636	(16,296)	11,959
Minority interest	–	–	238	–	238
	3,708	10,911	13,874	(16,296)	12,197

46. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

					$ million
For the year ended 31 December					2011
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	6,159	–	375,517	(6,159)	375,517
Earnings from jointly controlled entities – after interest and tax	–	–	1,304	–	1,304
Earnings from associates – after interest and tax	–	–	4,916	–	4,916
Equity-accounted income of subsidiaries – after interest and tax	313	26,158	–	(26,471)	–
Interest and other revenues	10	242	664	(320)	596
Gains on sale of businesses and fixed assets	–	1	4,129	–	4,130
Total revenues and other income	6,482	26,401	386,530	(32,950)	386,463
Purchases	978	–	290,799	(6,159)	285,618
Production and manufacturing expenses	1,280	–	22,865	–	24,145
Production and similar taxes	1,684	–	6,596	–	8,280
Depreciation, depletion and amortization	335	–	10,800	–	11,135
Impairment and losses on sale of businesses and fixed assets	–	–	2,058	–	2,058
Exploration expense	4	–	1,516	–	1,520
Distribution and administration expenses	27	1,048	12,992	(109)	13,958
Fair value gain on embedded derivatives	–	–	(68)	–	(68)
Profit before interest and taxation	2,174	25,353	38,972	(26,682)	39,817
Finance costs	32	47	1,378	(211)	1,246
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(533)	270	–	(263)
Profit before taxation	2,142	25,839	37,324	(26,471)	38,834
Taxation	729	139	11,869	–	12,737
Profit for the year	1,413	25,700	25,455	(26,471)	26,097
Attributable to					
BP shareholders	1,413	25,700	25,058	(26,471)	25,700
Minority interest	–	–	397	–	397
	1,413	25,700	25,455	(26,471)	26,097

Statement of comprehensive income continued

					$ million
For the year ended 31 December					2011
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit for the year	1,413	25,700	25,455	(26,471)	26,097
Currency translation differences	–	164	(695)	–	(531)
Exchange (gains) or losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	–	–	19	–	19
Actuarial loss relating to pensions and other post-retirement benefits	–	(4,770)	(1,190)	–	(5,960)
Available-for-sale investments marked to market	–	–	(71)	–	(71)
Available-for-sale – recycled to the income statement	–	–	(3)	–	(3)
Cash flow hedges marked to market	–	–	44	–	44
Cash flow hedges – recycled to the income statement	–	–	(195)	–	(195)
Cash flow hedges – recycled to the balance sheet	–	–	(13)	–	(13)
Share of equity-accounted entities' other comprehensive income, net of tax	–	–	(57)	–	(57)
Taxation	–	583	1,076	–	1,659
Other comprehensive income	–	(4,023)	(1,085)	–	(5,108)
Total comprehensive income	1,413	21,677	24,370	(26,471)	20,989
Attributable to					
BP shareholders	1,413	21,677	23,986	(26,471)	20,605
Minority interest	–	–	384	–	384
	1,413	21,677	24,370	(26,471)	20,989

46. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

$ million

For the year ended 31 December					2010
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,793	–	297,107	(4,793)	297,107
Earnings from jointly controlled entities – after interest and tax	–	–	1,175	–	1,175
Earnings from associates – after interest and tax	–	–	3,582	–	3,582
Equity-accounted income of subsidiaries – after interest and tax	620	(3,567)	–	2,947	–
Interest and other revenues	–	188	714	(221)	681
Gains on sale of businesses and fixed assets	–	260	6,376	(253)	6,383
Total revenues and other income	5,413	(3,119)	308,954	(2,320)	308,928
Purchases	637	–	220,367	(4,793)	216,211
Production and manufacturing expenses	966	–	63,649	–	64,615
Production and similar taxes	998	–	4,246	–	5,244
Depreciation, depletion and amortization	351	–	10,813	–	11,164
Impairment and losses on sale of businesses and fixed assets	1,524	–	1,689	(1,524)	1,689
Exploration expense	–	–	843	–	843
Distribution and administration expenses	16	673	11,975	(109)	12,555
Fair value loss on embedded derivatives	–	–	309	–	309
Profit (loss) before interest and taxation	921	(3,792)	(4,937)	4,106	(3,702)
Finance costs	2	31	1,249	(112)	1,170
Net finance (income) expense relating to pensions and other post-retirement benefits	4	(388)	337	–	(47)
Profit (loss) before taxation	915	(3,435)	(6,523)	4,218	(4,825)
Taxation	143	31	(1,675)	–	(1,501)
Profit (loss) for the year	772	(3,466)	(4,848)	4,218	(3,324)
Attributable to					
BP shareholders	772	(3,466)	(5,243)	4,218	(3,719)
Minority interest	–	–	395	–	395
	772	(3,466)	(4,848)	4,218	(3,324)

Statement of comprehensive income continued

$ million

For the year ended 31 December					2010
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	772	(3,466)	(4,848)	4,218	(3,324)
Currency translation differences	–	(45)	304	–	259
Exchange (gains) or losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	–	–	(20)	–	(20)
Actuarial loss relating to pensions and other post-retirement benefits	–	457	(777)	–	(320)
Available-for-sale investments marked to market	–	–	(191)	–	(191)
Available-for-sale – recycled to the income statement	–	–	(150)	–	(150)
Cash flow hedges marked to market	–	–	(65)	–	(65)
Cash flow hedges – recycled to the income statement	–	–	(25)	–	(25)
Cash flow hedges – recycled to the balance sheet	–	–	53	–	53
Share of equity-accounted entities' other comprehensive income, net of tax	–	–	–	–	–
Taxation	–	(123)	(14)	–	(137)
Other comprehensive income	–	289	(885)	–	(596)
Total comprehensive income	772	(3,177)	(5,733)	4,218	(3,920)
Attributable to					
BP shareholders	772	(3,177)	(6,131)	4,218	(4,318)
Minority interest	–	–	398	–	398
	772	(3,177)	(5,733)	4,218	(3,920)

46. Condensed consolidating information on certain US subsidiaries continued

Balance sheet

$ million

At 31 December					2012
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	8,343	–	112,105	–	120,448
Goodwill	–	–	11,861	–	11,861
Intangible assets	379	–	23,662	–	24,041
Investments in jointly controlled entities	–	–	15,724	–	15,724
Investments in associates	–	2	2,996	–	2,998
Other investments	–	–	2,702	–	2,702
Subsidiaries – equity-accounted basis	–	136,421	–	(136,421)	–
Fixed assets	8,722	136,423	169,050	(136,421)	177,774
Loans	–	–	4,977	(4,282)	695
Other receivables	–	–	4,754	–	4,754
Derivative financial instruments	–	–	4,294	–	4,294
Prepayments	34	–	775	–	809
Deferred tax assets	–	–	874	–	874
Defined benefit pension plan surpluses	–	–	12	–	12
	8,756	136,423	184,736	(140,703)	189,212
Current assets					
Loans	–	–	247	–	247
Inventories	174	–	27,693	–	27,867
Trade and other receivables	11,835	17,496	43,061	(34,728)	37,664
Derivative financial instruments	–	–	4,507	–	4,507
Prepayments	15	–	1,043	–	1,058
Current tax receivable	–	–	456	–	456
Other investments	–	–	319	–	319
Cash and cash equivalents	–	9	19,539	–	19,548
	12,024	17,505	96,865	(34,728)	91,666
Assets classified as held for sale	–	–	19,315	–	19,315
	12,024	17,505	116,180	(34,728)	110,981
Total assets	20,780	153,928	300,916	(175,431)	300,193
Current liabilities					
Trade and other payables	3,914	2,577	75,391	(34,728)	47,154
Derivative financial instruments	–	–	2,658	–	2,658
Accruals	140	27	6,643	–	6,810
Finance debt	–	–	10,030	–	10,030
Current tax payable	145	–	2,356	–	2,501
Provisions	1	–	7,586	–	7,587
	4,200	2,604	104,664	(34,728)	76,740
Liabilities directly associated with assets classified as held for sale	–	–	846	–	846
	4,200	2,604	105,510	(34,728)	77,586
Non-current liabilities					
Other payables	8	4,449	1,927	(4,282)	2,102
Derivative financial instruments	–	–	2,723	–	2,723
Accruals	–	38	410	–	448
Finance debt	–	–	38,767	–	38,767
Deferred tax liabilities	1,654	–	13,410	–	15,064
Provisions	1,887	–	28,447	–	30,334
Defined benefit pension plan and other post-retirement benefit plan deficits	–	1,913	11,636	–	13,549
	3,549	6,400	97,320	(4,282)	102,987
Total liabilities	7,749	9,004	202,830	(39,010)	180,573
Net assets	13,031	144,924	98,086	(136,421)	119,620
Equity					
BP shareholders' equity	13,031	144,924	96,880	(136,421)	118,414
Minority interest	–	–	1,206	–	1,206
Total equity	13,031	144,924	98,086	(136,421)	119,620

46. Condensed consolidating information on certain US subsidiaries continued

Balance sheet continued

					$ million
At 31 December					2011
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	8,653	–	110,561	–	119,214
Goodwill	–	–	12,100	–	12,100
Intangible assets	456	–	20,646	–	21,102
Investments in jointly controlled entities	–	–	15,518	–	15,518
Investments in associates	–	2	13,289	–	13,291
Other investments	–	–	2,633	–	2,633
Subsidiaries – equity-accounted basis	4,802	129,042	–	(133,844)	–
Fixed assets	13,911	129,044	174,747	(133,844)	183,858
Loans	46	38	5,113	(4,313)	884
Other receivables	–	–	4,337	–	4,337
Derivative financial instruments	–	–	5,038	–	5,038
Prepayments	–	–	739	–	739
Deferred tax assets	–	–	611	–	611
Defined benefit pension plan surpluses	–	–	17	–	17
	13,957	129,082	190,602	(138,157)	195,484
Current assets					
Loans	–	–	244	–	244
Inventories	167	–	25,494	–	25,661
Trade and other receivables	4,109	17,698	49,753	(28,034)	43,526
Derivative financial instruments	–	–	3,857	–	3,857
Prepayments	7	–	1,279	–	1,286
Current tax receivable	–	–	235	–	235
Other investments	–	–	288	–	288
Cash and cash equivalents	(1)	–	14,068	–	14,067
	4,282	17,698	95,218	(28,034)	89,164
Assets classified as held for sale	–	–	8,420	–	8,420
	4,282	17,698	103,638	(28,034)	97,584
Total assets	18,239	146,780	294,240	(166,191)	293,068
Current liabilities					
Trade and other payables	5,035	2,390	73,014	(28,034)	52,405
Derivative financial instruments	–	–	3,220	–	3,220
Accruals	–	28	5,904	–	5,932
Finance debt	–	–	9,044	–	9,044
Current tax payable	287	–	1,654	–	1,941
Provisions	–	–	11,238	–	11,238
	5,322	2,418	104,074	(28,034)	83,780
Liabilities directly associated with assets classified as held for sale	–	–	538	–	538
	5,322	2,418	104,612	(28,034)	84,318
Non-current liabilities					
Other payables	9	4,264	3,477	(4,313)	3,437
Derivative financial instruments	–	–	3,773	–	3,773
Accruals	–	35	354	–	389
Finance debt	–	–	35,169	–	35,169
Deferred tax liabilities	1,966	–	13,112	–	15,078
Provisions	1,620	–	24,784	–	26,404
Defined benefit pension plan and other post-retirement benefit plan deficits	–	2,088	9,930	–	12,018
	3,595	6,387	90,599	(4,313)	96,268
Total liabilities	8,917	8,805	195,211	(32,347)	180,586
Net assets	9,322	137,975	99,029	(133,844)	112,482
Equity					
BP shareholders’ equity	9,322	137,975	98,012	(133,844)	111,465
Minority interest	–	–	1,017	–	1,017
Total equity	9,322	137,975	99,029	(133,844)	112,482

46. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

$ million

For the year ended 31 December	**Issuer** **BP Exploration (Alaska) Inc.**	**Guarantor** **BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**2012** **BP group**
Net cash provided by operating activities	**681**	**12,381**	**20,850**	**(13,515)**	**20,397**
Net cash used in investing activities	**(680)**	**(7,060)**	**(5,222)**	**–**	**(12,962)**
Net cash used in financing activities	**–**	**(5,312)**	**(10,221)**	**13,515**	**(2,018)**
Currency translation differences relating to cash and cash equivalents	**–**	**–**	**64**	**–**	**64**
Increase in cash and cash equivalents	**1**	**9**	**5,471**	**–**	**5,481**
Cash and cash equivalents at beginning of year	**(1)**	**–**	**14,068**	**–**	**14,067**
Cash and cash equivalents at end of year	**–**	**9**	**19,539**	**–**	**19,548**

$ million

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	2011 BP group
Net cash provided by operating activities	661	8,321	25,114	(11,942)	22,154
Net cash used in investing activities	(661)	(3,710)	(22,262)	–	(26,633)
Net cash (used in) provided by financing activities	–	(4,615)	(6,845)	11,942	482
Currency translation differences relating to cash and cash equivalents	–	–	(492)	–	(492)
Decrease in cash and cash equivalents	–	(4)	(4,485)	–	(4,489)
Cash and cash equivalents at beginning of year	(1)	4	18,553	–	18,556
Cash and cash equivalents at end of year	(1)	–	14,068	–	14,067

$ million

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	2010 BP group
Net cash provided by (used in) operating activities	829	32,111	(4,584)	(14,740)	13,616
Net cash (used in) provided by investing activities	(752)	(29,325)	26,117	–	(3,960)
Net cash (used in) provided by financing activities	(56)	(2,810)	(11,034)	14,740	840
Currency translation differences relating to cash and cash equivalents	–	–	(279)	–	(279)
Increase (decrease) in cash and cash equivalents	21	(24)	10,220	–	10,217
Cash and cash equivalents at beginning of year	(22)	28	8,333	–	8,339
Cash and cash equivalents at end of year	(1)	4	18,553	–	18,556

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 SEC and FASB requirements.

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 favourable than in the reservoir as a whole, the operation of an installed programme 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 programme 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 with 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 84-86.

Oil and natural gas exploration and production activities

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2012
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		Total
Subsidiaries[a]										
Capitalized costs at 31 December[b,j]										
Gross capitalized costs										
Proved properties	28,370	9,421	70,133	219	8,153	32,755	—	16,757	3,676	169,484
Unproved properties	400	199	7,084	1,659	3,590	4,524	—	4,920	1,540	23,916
	28,770	9,620	77,217	1,878	11,743	37,279	—	21,677	5,216	193,400
Accumulated depreciation	19,002	3,161	35,459	197	4,444	16,901	—	8,360	1,517	89,041
Net capitalized costs	9,768	6,459	41,758	1,681	7,299	20,378	—	13,317	3,699	104,359
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c,k]										
Proved	—	—	256	—	51	—	—	—	—	307
Unproved	—	—	1,111	—	27	239	—	(68)	—	1,309
	—	—	1,367	—	78	239	—	(68)	—	1,616
Exploration and appraisal costs[d]	173	47	1,069	191	758	1,024	—	814	241	4,317
Development	1,907	784	3,866	22	581	2,992	—	1,591	221	11,964
Total costs	2,080	831	6,302	213	1,417	4,255	—	2,337	462	17,897
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	1,595	76	453	10	2,026	3,424	—	1,299	1,749	10,632
Sales between businesses	2,975	783	15,713	10	984	5,633	—	11,345	915	38,358
	4,570	859	16,166	20	3,010	9,057	—	12,644	2,664	48,990
Exploration expenditure	105	29	649	4	120	310	—	126	132	1,475
Production costs	1,310	348	3,854	71	812	1,323	—	1,076	191	8,985
Production taxes	92	—	1,472	—	162	—	—	6,291	141	8,158
Other costs (income)[f]	(1,474)	78	3,505	60	109	221	(330)	84	264	2,517
Depreciation, depletion and amortization	1,102	145	3,187	10	606	2,281	—	2,116	211	9,658
Impairments and (gains) losses on sale of businesses and fixed assets	373	83	(3,576)	98	6	24	—	(2)	(5)	(2,999)
	1,508	683	9,091	243	1,815	4,159	(330)	9,691	934	27,794
Profit (loss) before taxation[g]	3,062	176	7,075	(223)	1,195	4,898	330	2,953	1,730	21,196
Allocable taxes	1,121	(313)	2,762	(67)	804	2,371	(13)	663	755	8,083
Results of operations	1,941	489	4,313	(156)	391	2,527	343	2,290	975	13,113
Upstream segment and TNK-BP segment replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	3,062	176	7,075	(223)	1,195	4,898	330	2,953	1,730	21,196
Midstream activities and other activities – subsidiaries[h]	(250)	(114)	(173)	774	4	(46)	11	32	370	608
Equity-accounted entities[i]	—	35	16	43	256	48	3,005	640	—	4,043
Total replacement cost profit before interest and tax	2,812	97	6,918	594	1,455	4,900	3,346	3,625	2,100	25,847

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. They do not include any costs relating to the Gulf of Mexico oil spill. 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.

[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 $347 million. The UK region includes a $1,161 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme. The Russia region, for which equity accounting ceased on 22 October 2012, includes dividend income of $709 million partly offset by a settlement charge of $325 million.

[g] Excludes the unwinding of the discount on provisions and payables amounting to $227 million which is included in finance costs in the group income statement.

[h] Midstream and other activities exclude inventory holding gains and losses.

[i] The profits of equity-accounted entities are included after interest and tax and the results exclude balances associated with assets held for sale.

[j] Excludes balances associated with assets held for sale.

[k] Excludes goodwill associated with business combinations.

$ million

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[g]	Rest of Asia		2012
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	—	—	—	**1,694**	**6,958**	—	—	**4,036**	—	**12,688**
Unproved properties	—	—	—	**583**	**21**	—	—	**16**	—	**620**
	—	—	—	**2,277**	**6,979**	—	—	**4,052**	—	**13,308**
Accumulated depreciation	—	—	—	—	**2,965**	—	—	**3,648**	—	**6,613**
Net capitalized costs	—	—	—	**2,277**	**4,014**	—	—	**404**	—	**6,695**
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	**4**	—	—	**4**
Unproved	—	—	—	—	**439**	—	**15**	—	—	**454**
	—	—	—	—	**439**	—	**19**	—	—	**458**
Exploration and appraisal costs[d]	—	—	—	**31**	**31**	—	**195**	**7**	—	**264**
Development	—	—	—	**568**	**599**	—	**1,560**	**556**	—	**3,283**
Total costs	—	—	—	**599**	**1,069**	—	**1,774**	**563**	—	**4,005**
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	—	—	—	—	**2,267**	—	**6,472**	**4,245**	—	**12,984**
Sales between businesses	—	—	—	—	—	—	**3,639**	**21**	—	**3,660**
	—	—	—	—	**2,267**	—	**10,111**	**4,266**	—	**16,644**
Exploration expenditure	—	—	—	—	**31**	—	**93**	**1**	—	**125**
Production costs	—	—	—	—	**555**	—	**1,605**	**295**	—	**2,455**
Production taxes	—	—	—	—	**959**	—	**4,400**	**3,245**	—	**8,604**
Other costs (income)	—	—	—	**(43)**	**(11)**	—	**(24)**	**(2)**	—	**(80)**
Depreciation, depletion and amortization	—	—	—	—	**328**	—	**786**	**538**	—	**1,652**
Impairments and losses on sale of businesses and fixed assets	—	—	—	—	—	—	**(27)**	—	—	**(27)**
	—	—	—	**(43)**	**1,862**	—	**6,833**	**4,077**	—	**12,729**
Profit (loss) before taxation	—	—	—	**43**	**405**	—	**3,278**	**189**	—	**3,915**
Allocable taxes	—	—	—	—	**294**	—	**536**	**54**	—	**884**
Results of operations	—	—	—	**43**	**111**	—	**2,742**	**135**	—	**3,031**
Exploration and production activities – equity-accounted entities after tax (as above)	—	—	—	**43**	**111**	—	**2,742**	**135**	—	**3,031**
Midstream and other activities after tax[f]	—	**35**	**16**	—	**145**	**48**	**263**	**505**	—	**1,012**
Total replacement cost profit after interest and tax	—	**35**	**16**	**43**	**256**	**48**	**3,005**	**640**	—	**4,043**

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[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. Capitalized costs exclude balances associated with assets held for sale.

[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 and sales taxes.

[f] Includes interest, minority interest and the net results of equity-accounted entities of equity-accounted entities, and excludes inventory holding gains and losses.

[g] The Russia region includes BP's equity accounted share of TNK-BP's earnings. For 2012, equity accounted earnings are included until 21 October only, after which our investment was classified as an asset held for sale and therefore equity accounting ceased. The amounts shown exclude BP's share of costs incurred and results of operations for the period 22 October to 31 December 2012.

Oil and natural gas exploration and production activities continued

										$ million
										2011
	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, j]										
Gross capitalized costs										
Proved properties	37,491	8,994	73,626	182	7,471	29,358	–	14,833	3,370	175,325
Unproved properties	368	180	6,198	1,471	2,986	3,689	–	4,495	1,279	20,666
	37,859	9,174	79,824	1,653	10,457	33,047	–	19,328	4,649	195,991
Accumulated depreciation	26,953	3,715	36,009	139	3,839	14,595	–	6,235	1,294	92,779
Net capitalized costs	10,906	5,459	43,815	1,514	6,618	18,452	–	13,093	3,355	103,212
Costs incurred for the year ended 31 December[b, j]										
Acquisition of properties[c, k]										
Proved	–	–	1,178	8	237	–	–	1,733	–	3,156
Unproved	–	1	418	–	2,592	679	–	3,008	–	6,698
	–	1	1,596	8	2,829	679	–	4,741	–	9,854
Exploration and appraisal costs[d]	211	1	566	117	271	490	6	511	225	2,398
Development	1,361	889	3,016	–	405	2,933	–	1,340	251	10,195
Total costs	1,572	891	5,178	125	3,505	4,102	6	6,592	476	22,447
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	1,997	–	751	25	2,263	3,353	–	1,450	1,611	11,450
Sales between businesses	3,495	1,273	19,089	20	1,409	4,858	–	10,811	967	41,922
	5,492	1,273	19,840	45	3,672	8,211	–	12,261	2,578	53,372
Exploration expenditure	37	1	1,065	9	35	163	6	134	70	1,520
Production costs	1,372	230	3,402	66	503	1,146	4	787	194	7,704
Production taxes	72	–	1,854	–	278	–	–	5,956	147	8,307
Other costs (income)[f]	(1,357)	101	4,688	49	935	215	72	118	257	5,078
Depreciation, depletion and amortization	874	199	2,980	6	523	1,668	–	1,692	172	8,114
Impairments and (gains) losses on sale of businesses and fixed assets	26	(64)	(492)	15	(1,085)	18	(1)	(537)	–	(2,120)
	1,024	467	13,497	145	1,189	3,210	81	8,150	840	28,603
Profit (loss) before taxation[g]	4,468	806	6,343	(100)	2,483	5,001	(81)	4,111	1,738	24,769
Allocable taxes	2,483	384	2,152	(159)	1,205	2,184	(21)	1,001	677	9,906
Results of operations	1,985	422	4,191	59	1,278	2,817	(60)	3,110	1,061	14,863
Upstream segment and TNK-BP segment replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	4,468	806	6,343	(100)	2,483	5,001	(81)	4,111	1,738	24,769
Midstream activities – subsidiaries[h]	(118)	29	(157)	299	(58)	(4)	(1)	42	284	316
Equity-accounted entities[i]	–	12	10	58	598	69	4,095	573	–	5,415
Total replacement cost profit before interest and tax	4,350	847	6,196	257	3,023	5,066	4,013	4,726	2,022	30,500

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. They do not include any costs relating to the Gulf of Mexico oil spill. 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.

[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 $191 million. The UK region includes a $1,442 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme. The South America region includes a charge of $700 million associated with the termination of the agreement to sell our 60% interest in Pan American Energy LLC to Bridas Corporation.

[g] Excludes the unwinding of the discount on provisions and payables amounting to $352 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] Excludes balances associated with assets held for sale.

[k] Excludes goodwill associated with business combinations.

Oil and natural gas exploration and production activities continued

										$ million
										2011
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America[g]			Russia	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	–	–	–	1,125	6,562	–	16,214	3,684	–	27,585
Unproved properties	–	–	–	553	19	–	652	9	–	1,233
	–	–	–	1,678	6,581	–	16,866	3,693	–	28,818
Accumulated depreciation	–	–	–	–	2,644	–	6,978	3,017	–	12,639
Net capitalized costs	–	–	–	1,678	3,937	–	9,888	676	–	16,179
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	–	–	–	–	–	46	–	46
Unproved	–	–	–	–	6	–	37	–	–	43
	–	–	–	–	6	–	37	46	–	89
Exploration and appraisal costs[d]	–	–	–	19	2	–	167	9	–	197
Development	–	–	–	232	587	–	1,862	435	–	3,116
Total costs	–	–	–	251	595	–	2,066	490	–	3,402
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	–	–	–	–	2,381	–	7,380	3,828	–	13,589
Sales between businesses	–	–	–	–	–	–	5,149	23	–	5,172
	–	–	–	–	2,381	–	12,529	3,851	–	18,761
Exploration expenditure	–	–	–	–	10	–	72	1	–	83
Production costs	–	–	–	–	459	–	1,846	212	–	2,517
Production taxes	–	–	–	–	1,098	–	5,000	3,125	–	9,223
Other costs (income)	–	–	–	–	(239)	–	2	(1)	–	(238)
Depreciation, depletion and amortization	–	–	–	–	329	–	988	431	–	1,748
Impairments and (gains) losses on sale of businesses and fixed assets	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	1,657	–	7,908	3,768	–	13,333
Profit (loss) before taxation	–	–	–	–	724	–	4,621	83	–	5,428
Allocable taxes	–	–	–	–	294	–	806	19	–	1,119
Results of operations	–	–	–	–	430	–	3,815	64	–	4,309
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	–	430	–	3,815	64	–	4,309
Midstream and other activities after tax[f]	–	12	10	58	168	69	280	509	–	1,106
Total replacement cost profit after interest and tax	–	12	10	58	598	69	4,095	573	–	5,415

[a] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. 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 and sales taxes.

[f] Includes interest, minority interest and the net results of equity-accounted entities of equity-accounted entities, and excludes inventory holding gains and losses.

[g] An amendment has been made to the classification of costs between proved and unproved properties.

Oil and natural gas exploration and production activities continued

$ million

2010

	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,j]										
Gross capitalized costs										
Proved properties	36,161	7,846	67,724	278	6,047	27,014	–	11,497	3,088	159,655
Unproved properties	787	179	5,968	1,363	220	2,694	–	1,113	1,149	13,473
	36,948	8,025	73,692	1,641	6,267	29,708	–	12,610	4,237	173,128
Accumulated depreciation	27,688	3,515	33,972	216	3,282	13,893	–	4,569	1,205	88,340
Net capitalized costs	9,260	4,510	39,720	1,425	2,985	15,815	–	8,041	3,032	84,788
Costs incurred for the year ended 31 December[b,j]										
Acquisition of properties[c]										
Proved	–	–	655	1	–	–	–	1,121	–	1,777
Unproved	–	519	1,599	1,200	–	–	–	151	–	3,469
	–	519	2,254	1,201	–	–	–	1,272	–	5,246
Exploration and appraisal costs[d]	401	13	1,096	78	68	607	7	316	120	2,706
Development	726	816	3,034	251	414	3,003	–	1,244	187	9,675
Total costs	1,127	1,348	6,384	1,530	482	3,610	7	2,832	307	17,627
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	1,472	58	1,148	90	1,896	3,158	–	1,272	1,398	10,492
Sales between businesses	3,405	1,134	18,819	453	1,574	4,353	–	6,697	929	37,364
	4,877	1,192	19,967	543	3,470	7,511	–	7,969	2,327	47,856
Exploration expenditure	82	(2)	465	25	9	189	7	51	17	843
Production costs	1,018	152	2,867	240	445	938	9	365	124	6,158
Production taxes	52	–	1,093	2	249	–	–	3,764	109	5,269
Other costs (income)[f]	(316)	76	3,502	129	209	130	76	90	195	4,091
Depreciation, depletion and amortization	897	209	3,477	95	575	1,771	–	829	168	8,021
Impairments and (gains) losses on sale of businesses and fixed assets	(1)	–	(1,441)	(2,190)	(3)	(427)	341[k]	–	–	(3,721)
	1,732	435	9,963	(1,699)	1,484	2,601	433	5,099	613	20,661
Profit (loss) before taxation[g]	3,145	757	10,004	2,242	1,986	4,910	(433)	2,870	1,714	27,195
Allocable taxes	1,333	530	3,504	610	1,084	1,771	(23)	813	410	10,032
Results of operations	1,812	227	6,500	1,632	902	3,139	(410)	2,057	1,304	17,163
Upstream segment and TNK-BP segment replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	3,145	757	10,004	2,242	1,986	4,910	(433)	2,870	1,714	27,195
Midstream activities – subsidiaries[h]	23	42	(347)	3	49	(26)	4	(23)	(13)	(288)
Equity-accounted entities[i]	–	4	27	171	614	63	2,613	487	–	3,979
Total replacement cost profit before interest and tax	3,168	803	9,684	2,416	2,649	4,947	2,184	3,334	1,701	30,886

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. They do not include any costs relating to the Gulf of Mexico oil spill. 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.

[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 loss on embedded derivatives of $309 million. The UK region includes a $822 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 $313 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] Excludes balances associated with assets held for sale.

[k] This amount represents the write-down of our investment in Sakhalin. A portion of these costs was previously reported within capitalized costs of equity-accounted entities with the remainder previously reported as a loan, which was not included in the disclosures of oil and natural gas exploration and production activities.

Oil and natural gas exploration and production activities continued

										$ million
										2010
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America[g]			Russia	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	–	–	–	893	5,778	–	14,486	3,192	–	24,349
Unproved properties	–	–	–	533	163	–	652	–	–	1,348
	–	–	–	1,426	5,941	–	15,138	3,192	–	25,697
Accumulated depreciation	–	–	–	–	2,250	–	6,300	2,674	–	11,224
Net capitalized costs	–	–	–	1,426	3,691	–	8,838	518	–	14,473
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	9	–	66	–	–	75
	–	–	–	–	9	–	66	–	–	75
Exploration and appraisal costs[d]	–	–	–	28	2	–	94	–	–	124
Development	–	–	–	21	549	–	1,416	355	–	2,341
Total costs	–	–	–	49	560	–	1,576	355	–	2,540
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	–	–	–	–	2,268	–	5,610	2,557	–	10,435
Sales between businesses	–	–	–	–	–	–	3,432	19	–	3,451
	–	–	–	–	2,268	–	9,042	2,576	–	13,886
Exploration expenditure	–	–	–	–	22	–	40	–	–	62
Production costs	–	–	–	–	316	–	1,602	184	–	2,102
Production taxes	–	–	–	–	911	–	3,567	2,029	–	6,507
Other costs (income)	–	–	–	67	75	–	3	(2)	–	143
Depreciation, depletion and amortization	–	–	–	–	269	–	954	363	–	1,586
Impairments and losses on sale of businesses and fixed assets	–	–	–	–	–	–	43	–	–	43
	–	–	–	67	1,593	–	6,209	2,574	–	10,443
Profit (loss) before taxation	–	–	–	(67)	675	–	2,833	2	–	3,443
Allocable taxes	–	–	–	–	260	–	475	33	–	768
Results of operations	–	–	–	(67)	415	–	2,358	(31)	–	2,675
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	(67)	415	–	2,358	(31)	–	2,675
Midstream and other activities after tax[f]	–	4	27	238	199	63	255	518	–	1,304
Total replacement cost profit after interest and tax	–	4	27	171	614	63	2,613	487	–	3,979

[a] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. 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 and sales taxes.

[f] Includes interest, minority interest and the net results of equity-accounted entities of equity-accounted entities.

[g] An amendment has been made to the classification of costs between proved and unproved properties.

Movements in estimated net proved reserves

million barrels

Crude oil[a]										2012
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[b]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2012										
Developed	288	69	1,685	–	27	311	–	177	59	2,616
Undeveloped	445	230	1,173	–	48	315	–	279	47	2,537
	733	299	2,858	–	75	626	–	456	106	5,153
Changes attributable to										
Revisions of previous estimates	(30)	(25)	(280)	–	(11)	(1)	–	(2)	–	(349)
Improved recovery	3	–	140	–	–	13	–	2	–	158
Purchases of reserves-in-place	4	–	21	–	–	–	–	–	–	25
Discoveries and extensions	–	1	23	–	–	2	–	–	–	26
Production[c]	(31)	(8)	(142)	–	(10)	(73)	–	(51)	(9)	(324)
Sales of reserves-in-place	(6)	(18)	(188)	–	–	–	–	–	–	(212)
	(60)	(50)	(426)	–	(21)	(59)	–	(51)	(9)	(676)
At 31 December 2012[d h]										
Developed	242	170	1,443	–	22	312	–	268	52	2,509
Undeveloped	431	79	989	–	32	255	–	137	45	1,968
	673	249	2,432	–	54	567	–	405	97	4,477
Equity-accounted entities (BP share)[e]										
At 1 January 2012										
Developed	–	–	–	–	349	–	2,596	256	–	3,201
Undeveloped	–	–	–	–	348	14	1,613	58	–	2,033
	–	–	–	–	697	14	4,209	314	–	5,234
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(2)	9	462	(23)	–	446
Improved recovery	–	–	–	–	24	–	47	–	–	71
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	67	–	–	67
Production	–	–	–	–	(29)	–	(316)	(80)	–	(425)
Sales of reserves-in-place	–	–	–	–	–	–	(15)	–	–	(15)
	–	–	–	–	(7)	9	245	(103)	–	144
At 31 December 2012[f g i]										
Developed	–	–	–	–	339	12	2,492	198	–	3,041
Undeveloped	–	–	–	–	351	11	1,962	13	–	2,337
	–	–	–	–	690	23	4,454	211	–	5,378
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2012										
Developed	288	69	1,685	–	376	311	2,596	433	59	5,817
Undeveloped	445	230	1,173	–	396	329	1,613	337	47	4,570
	733	299	2,858	–	772	640	4,209	770	106	10,387
At 31 December 2012										
Developed	242	170	1,443	–	361	324	2,492	466	52	5,550
Undeveloped	431	79	989	–	383	266	1,962	150	45	4,305
	673	249	2,432	–	744	590	4,454	616	97	9,855

[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] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 76 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.

[c] Excludes NGLs from processing plants in which an interest is held of 13,500 barrels per day.

[d] Includes 591 million barrels of NGLs. Also includes 14 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[f] Includes 103 million barrels of NGLs. Also includes 328 million barrels of crude oil in respect of the 7.35% minority interest in TNK-BP.

[g] Total proved liquid reserves held as part of our equity interest in TNK-BP is 4,540 million barrels, comprising 87 million barrels in Venezuela and 4,453 million barrels in Russia.

[h] Includes assets held for sale of 39 million barrels.

[i] Includes assets held for sale of 4,540 million barrels.

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	2012 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2012										
Developed	1,411	43	9,721	28	2,869	1,224	–	1,034	3,570	19,900
Undeveloped	909	450	3,831	–	6,529	2,033	–	364	2,365	16,481
	2,320	493	13,552	28	9,398	3,257	–	1,398	5,935	36,381
Changes attributable to										
Revisions of previous estimates	(18)	(13)	(1,853)	(19)	(116)	(14)	–	38	(41)	(2,036)
Improved recovery	95	–	885	–	756	69	–	156	–	1,961
Purchases of reserves-in-place	17	(1)	232	–	–	–	–	–	–	248
Discoveries and extensions	–	7	225	–	598	1	–	–	–	831
Production[b]	(164)	(5)	(661)	(5)	(775)	(251)	–	(253)	(289)	(2,403)
Sales of reserves-in-place	(546)	–	(1,149)	–	(23)	–	–	–	–	(1,718)
	(616)	(12)	(2,321)	(24)	440	(195)	–	(59)	(330)	(3,117)
At 31 December 2012[c g]										
Developed	1,038	340	8,245	4	3,588	1,139	–	926	3,282	18,562
Undeveloped	666	141	2,986	–	6,250	1,923	–	413	2,323	14,702
	1,704	481	11,231	4	9,838	3,062	–	1,339	5,605	33,264
Equity-accounted entities (BP share)[d]										
At 1 January 2012										
Developed	–	–	–	–	1,144	–	2,119	104	–	3,367
Undeveloped	–	–	–	–	1,006	195	659	51	–	1,911
	–	–	–	–	2,150	195	2,778	155	–	5,278
Changes attributable to										
Revisions of previous estimates	–	–	–	–	86	144	569	25	–	824
Improved recovery	–	–	–	–	110	–	–	1	–	111
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	3	–	1,310	–	–	1,313
Production[b]	–	–	–	–	(169)	–	(280)	(35)	–	(484)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	30	144	1,598	(9)	–	1,763
At 31 December 2012[e f h]										
Developed	–	–	–	–	1,276	175	2,617	128	–	4,196
Undeveloped	–	–	–	–	904	164	1,759	18	–	2,845
	–	–	–	–	2,180	339	4,376	146	–	7,041
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2012										
Developed	1,411	43	9,721	28	4,013	1,224	2,119	1,138	3,570	23,267
Undeveloped	909	450	3,831	–	7,535	2,228	659	415	2,365	18,392
	2,320	493	13,552	28	11,548	3,452	2,778	1,553	5,935	41,659
At 31 December 2012										
Developed	1,038	340	8,245	4	4,864	1,314	2,617	1,054	3,282	22,758
Undeveloped	666	141	2,986	–	7,154	2,087	1,759	431	2,323	17,547
	1,704	481	11,231	4	12,018	3,401	4,376	1,485	5,605	40,305

[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 190 billion cubic feet of natural gas consumed in operations, 145 billion cubic feet in subsidiaries, 45 billion cubic feet in equity-accounted entities and excludes 9 billion cubic feet of produced non-hydrocarbon components that meet regulatory requirements for sales.

[c] Includes 2,890 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[e] Includes 270 billion cubic feet of natural gas in respect of the 6.17% minority interest in TNK-BP.

[f] Total proved gas reserves held as part of our equity interest in TNK-BP is 4,492 billion cubic feet, comprising 38 billion cubic feet in Venezuela, 78 billion cubic feet in Vietnam and 4,376 billion cubic feet in Russia.

[g] includes assets held for sale of 590 billion cubic feet.

[h] includes assets held for sale of 4,492 billion cubic feet.

Movements in estimated net proved reserves continued

		million barrels
Bitumen[a]		**2012**
		Total
	Rest of North America	
Equity-accounted entities (BP share)		
At 1 January 2012		
Developed	**–**	**–**
Undeveloped	**178**	**178**
	178	**178**
Changes attributable to		
Revisions of previous estimates	**17**	**17**
Improved recovery	**–**	**–**
Purchases of reserves-in-place	**–**	**–**
Discoveries and extensions	**–**	**–**
Production	**–**	**–**
Sales of reserves-in-place	**–**	**–**
	17	**17**
At 31 December 2012		
Developed	**–**	**–**
Undeveloped	**195**	**195**
	195	**195**

[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.

Movements in estimated net proved reserves continued

million barrels of oil equivalent[b]

Total hydrocrabons[a]										2012
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2012										
Developed	531	76	3,362	5	522	522	–	355	675	6,048
Undeveloped	602	308	1,833	–	1,173	665	–	342	455	5,378
	1,133	384	5,195	5	1,695	1,187	–	697	1,130	11,426
Changes attributable to										
Revisions of previous estimates	(33)	(27)	(600)	(3)	(31)	(3)	–	5	(8)	(700)
Improved recovery	19	–	293	–	130	25	–	29	–	496
Purchases of reserves-in-place	7	–	61	–	–	–	–	–	–	68
Discoveries and extensions	–	2	62	–	103	2	–	–	–	169
Production[d e]	(59)	(9)	(256)	(1)	(143)	(116)	–	(95)	(59)	(738)
Sales of reserves-in-place	(100)	(18)	(386)	–	(4)	–	–	–	–	(508)
	(166)	(52)	(826)	(4)	55	(92)	–	(61)	(67)	(1,213)
At 31 December 2012[f j]										
Developed	421	229	2,865	1	640	508	–	427	618	5,709
Undeveloped	546	103	1,504	–	1,110	587	–	209	445	4,504
	967	332	4,369	1	1,750	1,095	–	636	1,063	10,213
Equity-accounted entities (BP share)[g]										
At 1 January 2012										
Developed	–	–	–	–	546	–	2,961	274	–	3,781
Undeveloped	–	–	–	178	522	48	1,727	66	–	2,541
	–	–	–	178	1,068	48	4,688	340	–	6,322
Changes attributable to										
Revisions of previous estimates	–	–	–	17	13	34	560	(19)	–	605
Improved recovery	–	–	–	–	43	–	47	–	–	90
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	1	–	292	–	–	293
Production[d e]	–	–	–	–	(58)	–	(364)	(86)	–	(508)
Sales of reserves-in-place	–	–	–	–	–	–	(15)	–	–	(15)
	–	–	–	17	(1)	34	520	(105)	–	465
At 31 December 2012[h i k]										
Developed	–	–	–	–	559	43	2,943	220	–	3,765
Undeveloped	–	–	–	195	508	39	2,265	15	–	3,022
	–	–	–	195	1,067	82	5,208	235	–	6,787
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2012										
Developed	531	76	3,362	5	1,068	522	2,961	629	675	9,829
Undeveloped	602	308	1,833	178	1,695	713	1,727	408	455	7,919
	1,133	384	5,195	183	2,763	1,235	4,688	1,037	1,130	17,748
At 31 December 2012										
Developed	421	229	2,865	1	1,199	551	2,943	647	618	9,474
Undeveloped	546	103	1,504	195	1,618	626	2,265	224	445	7,526
	967	332	4,369	196	2,817	1,177	5,208	871	1,063	17,000

[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] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 76 million barrels of oil equivalent 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.

[d] Excludes NGLs from processing plants in which an interest is held of 13,500 barrels of oil equivalent per day.

[e] Includes 33 million barrels of oil equivalent of natural gas consumed in operations, 25 million barrels of oil equivalent in subsidiaries, 8 million barrels of oil equivalent in equity-accounted entities and excludes 2 million barrels of oil equivalent of produced non-hydrocarbon components that meet regulatory requirements for sales.

[f] Includes 591 million barrels of NGLs. Also includes 512 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[h] Includes 103 million barrels of NGLs. Also includes 374 million barrels of oil equivalent in respect of the minority interest in TNK-BP.

[i] Total proved reserves held as part of our equity interest in TNK-BP is 5,315 million barrels of oil equivalent, comprising 93 million barrels of oil equivalent in Venezuela, 14 million barrels of oil equivalent in Vietnam and 5,208 million barrels of oil equivalent in Russia.

[j] includes assets held for sale of 140 million barrels of oil equivalent.

[k] includes assets held for sale of 5,315 million barrels of oil equivalent.

Movements in estimated net proved reserves continued

million barrels

Crude oil[a]										2011
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[b]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2011										
Developed	364	77	1,729	–	44	371	–	269	48	2,902
Undeveloped	431	221	1,190	–	58	374	–	325	58	2,657
	795	298	2,919	–	102	745	–	594	106	5,559
Changes attributable to										
Revisions of previous estimates	(1)	5	27	–	6	(68)	–	(131)	3	(159)
Improved recovery	14	8	97	–	1	10	–	70	6	206
Purchases of reserves-in-place	–	–	10	–	7	–	–	4	–	21
Discoveries and extensions	–	–	1	–	1	19	–	–	–	21
Production[c]	(41)	(12)	(162)	–	(13)	(68)	–	(50)	(9)	(355)
Sales of reserves-in-place	(34)	–	(34)	–	(29)	(12)	–	(31)	–	(140)
	(62)	1	(61)	–	(27)	(119)	–	(138)	–	(406)
At 31 December 2011[d]										
Developed	288	69	1,685	–	27	311	–	177	59	2,616
Undeveloped	445	230	1,173	–	48	315	–	279	47	2,537
	733	299	2,858	–	75	626	–	456	106	5,153
Equity-accounted entities (BP share)[e]										
At 1 January 2011										
Developed	–	–	–	–	408	–	2,388	370	–	3,166
Undeveloped	–	–	–	–	407	12	1,362	24	–	1,805
	–	–	–	–	815	12	3,750	394	–	4,971
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(12)	2	677	(5)	–	662
Improved recovery	–	–	–	–	70	–	73	–	–	143
Purchases of reserves-in-place	–	–	–	–	98	–	–	1	–	99
Discoveries and extensions	–	–	–	–	–	–	25	–	–	25
Production	–	–	–	–	(30)	–	(316)	(76)	–	(422)
Sales of reserves-in-place	–	–	–	–	(244)	–	–	–	–	(244)
	–	–	–	–	(118)	2	459	(80)	–	263
At 31 December 2011[f g]										
Developed	–	–	–	–	349	–	2,596	256	–	3,201
Undeveloped	–	–	–	–	348	14	1,613	58	–	2,033
	–	–	–	–	697	14	4,209	314	–	5,234
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	364	77	1,729	–	452	371	2,388	639	48	6,068
Undeveloped	431	221	1,190	–	465	386	1,362	349	58	4,462
	795	298	2,919	–	917	757	3,750	988	106	10,530
At 31 December 2011										
Developed	288	69	1,685	–	376	311	2,596	433	59	5,817
Undeveloped	445	230	1,173	–	396	329	1,613	337	47	4,570
	733	299	2,858	–	772	640	4,209	770	106	10,387

[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] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 82 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.

[c] Excludes NGLs from processing plants in which an interest is held of 28 thousand barrels per day.

[d] Includes 616 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.

[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[f] Includes 19 million barrels of NGLs. Also includes 310 million barrels of crude oil in respect of the 7.37% minority interest in TNK-BP.

[g] Total proved liquid reserves held as part of our equity interest in TNK-BP is 4,305 million barrels, comprising 95 million barrels in Venezuela, one million barrels in Vietnam and 4,209 million barrels in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved liquid reserves of 221 million barrels.

Movements in estimated net proved reserves continued

										billion cubic feet
Natural gas[a]										2011
	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 2011										
Developed	1,416	40	9,495	58	3,575	1,329	–	1,290	3,563	20,766
Undeveloped	829	430	4,248	–	6,575	2,351	–	268	2,342	17,043
	2,245	470	13,743	58	10,150	3,680	–	1,558	5,905	37,809
Changes attributable to										
Revisions of previous estimates	169	30	–	(9)	202	(206)	–	69	299	554
Improved recovery	56	1	597	–	84	15	–	28	22	803
Purchases of reserves-in-place	8	–	93	7	–	–	–	310	–	418
Discoveries and extensions	–	–	219	–	47	–	–	–	–	266
Production[b]	(146)	(8)	(737)	(5)	(811)	(232)	–	(244)	(291)	(2,474)
Sales of reserves-in-place	(12)	–	(363)	(23)	(274)	–	–	(323)	–	(995)
	75	23	(191)	(30)	(752)	(423)	–	(160)	30	(1,428)
At 31 December 2011[c]										
Developed	1,411	43	9,721	28	2,869	1,224	–	1,034	3,570	19,900
Undeveloped	909	450	3,831	–	6,529	2,033	–	364	2,365	16,481
	2,320	493	13,552	28	9,398	3,257	–	1,398	5,935	36,381
Equity-accounted entities (BP share)[d]										
At 1 January 2011										
Developed	–	–	–	–	1,075	–	1,900	71	–	3,046
Undeveloped	–	–	–	–	1,192	175	459	19	–	1,845
	–	–	–	–	2,267	175	2,359	90	–	4,891
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(75)	20	683	(3)	–	625
Improved recovery	–	–	–	–	190	–	–	12	–	202
Purchases of reserves-in-place	–	–	–	–	31	–	–	76	–	107
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production[b]	–	–	–	–	(167)	–	(264)	(20)	–	(451)
Sales of reserves-in-place	–	–	–	–	(96)	–	–	–	–	(96)
	–	–	–	–	(117)	20	419	65	–	387
At 31 December 2011[e f]										
Developed	–	–	–	–	1,144	–	2,119	104	–	3,367
Undeveloped	–	–	–	–	1,006	195	659	51	–	1,911
	–	–	–	–	2,150	195	2,778	155	–	5,278
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	1,416	40	9,495	58	4,650	1,329	1,900	1,361	3,563	23,812
Undeveloped	829	430	4,248	–	7,767	2,526	459	287	2,342	18,888
	2,245	470	13,743	58	12,417	3,855	2,359	1,648	5,905	42,700
At 31 December 2011										
Developed	1,411	43	9,721	28	4,013	1,224	2,119	1,138	3,570	23,267
Undeveloped	909	450	3,831	–	7,535	2,228	659	415	2,365	18,392
	2,320	493	13,552	28	11,548	3,452	2,778	1,553	5,935	41,659

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[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 196 billion cubic feet of natural gas consumed in operations,155 billion cubic feet in subsidiaries, 41 billion cubic feet in equity-accounted entities and excludes 14 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.

[c] Includes 2,759 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[e] Includes 174 billion cubic feet of natural gas in respect of the 6.27% minority interest in TNK-BP.

[f] Total proved gas reserves held as part of our equity interest in TNK-BP is 2,881 billion cubic feet, comprising 30 billion cubic feet in Venezuela, 73 billion cubic feet in Vietnam and 2,778 billion cubic feet in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved gas reserves of 185 billion cubic feet.

Movements in estimated net proved reserves continued

		million barrels
Bitumen[a]		2011
	Rest of North America	Total
Equity-accounted entities (BP share)		
At 1 January 2011		
Developed	–	–
Undeveloped	179	179
	179	179
Changes attributable to		
Revisions of previous estimates	(1)	(1)
Improved recovery	–	–
Purchases of reserves-in-place	–	–
Discoveries and extensions	–	–
Production	–	–
Sales of reserves-in-place	–	–
	(1)	(1)
At 31 December 2011		
Developed	–	–
Undeveloped	178	178
	178	178

[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.

Movements in estimated net proved reserves continued

million barrels of oil equivalent[b]

Total hydrocarbons[a]										2011
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2011										
Developed	608	84	3,366	10	660	600	–	491	662	6,481
Undeveloped	574	295	1,923	–	1,192	779	–	371	462	5,596
	1,182	379	5,289	10	1,852	1,379	–	862	1,124	12,077
Changes attributable to										
Revisions of previous estimates	28	10	27	(2)	41	(103)	–	(119)	55	(63)
Improved recovery	24	8	200	–	15	12	–	75	10	344
Purchases of reserves-in-place	1	–	26	2	7	–	–	58	–	94
Discoveries and extensions	–	–	39	–	9	19	–	–	–	67
Production[d e]	(66)	(13)	(289)	(1)	(153)	(108)	–	(92)	(59)	(781)
Sales of reserves-in-place	(36)	–	(97)	(4)	(76)	(12)	–	(87)	–	(312)
	(49)	5	(94)	(5)	(157)	(192)	–	(165)	6	(651)
At 31 December 2011[f]										
Developed	531	76	3,362	5	522	522	–	355	675	6,048
Undeveloped	602	308	1,833	–	1,173	665	–	342	455	5,378
	1,133	384	5,195	5	1,695	1,187	–	697	1,130	11,426
Equity-accounted entities (BP share)[g]										
At 1 January 2011										
Developed	–	–	–	–	593	–	2,716	382	–	3,691
Undeveloped	–	–	–	179	613	43	1,441	27	–	2,303
	–	–	–	179	1,206	43	4,157	409	–	5,994
Changes attributable to										
Revisions of previous estimates	–	–	–	(1)	(25)	5	795	(5)	–	769
Improved recovery	–	–	–	–	103	–	73	2	–	178
Purchases of reserves-in-place	–	–	–	–	103	–	–	14	–	117
Discoveries and extensions	–	–	–	–	–	–	25	–	–	25
Production[d e]	–	–	–	–	(59)	–	(362)	(80)	–	(501)
Sales of reserves-in-place	–	–	–	–	(260)	–	–	–	–	(260)
	–	–	–	(1)	(138)	5	531	(69)	–	328
At 31 December 2011[h i]										
Developed	–	–	–	–	546	–	2,961	274	–	3,781
Undeveloped	–	–	–	178	522	48	1,727	66	–	2,541
	–	–	–	178	1,068	48	4,688	340	–	6,322
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	608	84	3,366	10	1,253	600	2,716	873	662	10,172
Undeveloped	574	295	1,923	179	1,805	822	1,441	398	462	7,899
	1,182	379	5,289	189	3,058	1,422	4,157	1,271	1,124	18,071
At 31 December 2011										
Developed	531	76	3,362	5	1,068	522	2,961	629	675	9,829
Undeveloped	602	308	1,833	178	1,695	713	1,727	408	455	7,919
	1,133	384	5,195	183	2,763	1,235	4,688	1,037	1,130	17,748

[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] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 82 million barrels of oil equivalent 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.

[d] Excludes NGLs from processing plants in which an interest is held of 28 thousand barrels of oil equivalent a day.

[e] Includes 34 million barrels of oil equivalent of natural gas consumed in operations, 27 million barrels of oil equivalent in subsidiaries, seven million barrels of oil equivalent in equity-accounted entities and excludes two million barrels of oil equivalent of produced non-hydrocarbon components which meet regulatory requirements for sales.

[f] Includes 616 million barrels of NGLs. Also includes 496 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[h] Includes 19 million barrels of NGLs. Also includes 340 million barrels of oil equivalent in respect of the minority interest in TNK-BP.

[i] Total proved reserves held as part of our equity interest in TNK-BP is 4,802 million barrels of oil equivalent, comprising 100 million barrels of oil equivalent in Venezuela, 14 million barrels of oil equivalent in Vietnam and 4,688 million barrels of oil equivalent in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved reserves of 253 million barrels of oil equivalent.

Movements in estimated net proved reserves continued

										million barrels
Crude oil[a]										2010
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[b]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2010										
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
Changes attributable to										
Revisions of previous estimates	20	3	(45)	1	(1)	(62)	–	(62)	–	(146)
Improved recovery	100	9	133	–	17	14	–	145	3	421
Purchases of reserves-in-place	–	33	6	–	–	–	–	38	–	77
Discoveries and extensions	31	1	80	–	–	19	–	–	–	131
Production[c d]	(50)	(15)	(211)	(2)	(19)	(87)	–	(43)	(12)	(439)
Sales of reserves-in-place	–	–	(117)	(11)	–	(15)	–	–	–	(143)
	101	31	(154)	(12)	(3)	(131)	–	78	(9)	(99)
At 31 December 2010[e f]										
Developed	364	77	1,729	–	44	371	–	269	48	2,902
Undeveloped	431	221	1,190	–	58	374	–	325	58	2,657
	795	298	2,919	–	102	745	–	594	106	5,559
Equity-accounted entities (BP share)[g]										
At 1 January 2010										
Developed	–	–	–	–	407	–	2,351	363	–	3,121
Undeveloped	–	–	–	–	405	9	1,198	120	–	1,732
	–	–	–	–	812	9	3,549	483	–	4,853
Changes attributable to										
Revisions of previous estimates	–	–	–	–	4	3	248	(20)	–	235
Improved recovery	–	–	–	–	33	–	269	–	–	302
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	1	–	–	–	–	1
Production	–	–	–	–	(35)[h i]	–	(313)	(69)	–	(417)
Sales of reserves-in-place	–	–	–	–	–	–	(3)	–	–	(3)
	–	–	–	–	3	3	201	(89)	–	118
At 31 December 2010[j]										
Developed	–	–	–	–	408	–	2,388	370	–	3,166
Undeveloped	–	–	–	–	407	12	1,362	24	–	1,805
	–	–	–	–	815[k]	12	3,750	394	–	4,971
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2010										
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
At 31 December 2010										
Developed	364	77	1,729	–	452	371	2,388	639	48	6,068
Undeveloped	431	221	1,190	–	465	386	1,362	349	58	4,462
	795	298	2,919	–	917	757	3,750	988	106	10,530

[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] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 78 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.

[c] Excludes NGLs from processing plants in which an interest is held of 29 thousand barrels per day.

[d] Includes 15 million barrels of crude oil sold relating to production from assets held for sale at 31 December 2010. Amounts by region are: 2 million barrels in US; 6 million barrels in South America; and 7 million barrels in Rest of Asia.

[e] Includes 643 million barrels of NGLs. Also includes 22 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[f] Includes 70 million barrels relating to assets held for sale at 31 December 2010. Amounts by region are: 6 million barrels in US; 30 million barrels in South America; and 34 million barrels in Rest of Asia.

[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[h] Includes 2 million barrels of crude oil sold relating to production since classification of equity-accounted entities as held for sale.

[i] Includes 9 million barrels of crude oil sold relating to production from assets held for sale at 31 December 2010.

[j] Includes 18 million barrels of NGLs. Also includes 254 million barrels of crude oil in respect of the 7.03% minority interest in TNK-BP.

[k] Includes 213 million barrels relating to assets held for sale at 31 December 2010.

Movements in estimated net proved reserves continued

billion cubic feet

2010

Natural gas[a]	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 2010										
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
Changes attributable to										
Revisions of previous estimates	(8)	(5)	(1,854)	(11)	2	3	–	(142)	(191)	(2,206)
Improved recovery	152	6	830	–	512	18	–	83	58	1,659
Purchases of reserves-in-place	–	31	97	1	–	–	–	17	–	146
Discoveries and extensions	26	–	739	9	19	1,378	–	–	–	2,171
Production[b c]	(191)	(8)	(861)	(77)	(953)	(229)	–	(228)	(288)	(2,835)
Sales of reserves-in-place	(6)	–	(424)	(1,033)	–	(51)	–	–	–	(1,514)
	(27)	24	(1,473)	(1,111)	(420)	1,119	–	(270)	(421)	(2,579)
At 31 December 2010[d e]										
Developed	1,416	40	9,495	58	3,575	1,329	–	1,290	3,563	20,766
Undeveloped	829	430	4,248	–	6,575	2,351	–	268	2,342	17,043
	2,245	470	13,743	58	10,150	3,680	–	1,558	5,905	37,809
Equity-accounted entities (BP share)[f]										
At 1 January 2010										
Developed	–	–	–	–	1,252	–	1,703	80	–	3,035
Undeveloped	–	–	–	–	1,010	165	519	13	–	1,707
	–	–	–	–	2,262	165	2,222	93	–	4,742
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(141)	10	382	2	–	253
Improved recovery	–	–	–	–	291	–	–	12	–	303
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	23	–	–	–	–	23
Production[b]	–	–	–	–	(168)[g h]	–	(244)	(17)	–	(429)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	5	10	137	(3)	–	149
At 31 December 2010[i]										
Developed	–	–	–	–	1,075	–	1,900	71	–	3,046
Undeveloped	–	–	–	–	1,192	175	459	19	–	1,845
	–	–	–	–	2,267[j]	175	2,359	90	–	4,891
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2010										
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
At 31 December 2010										
Developed	1,416	40	9,495	58	4,650	1,329	1,900	1,361	3,563	23,812
Undeveloped	829	430	4,248	–	7,767	2,526	459	287	2,342	18,888
	2,245	470	13,743	58	12,417	3,855	2,359	1,648	5,905	42,700

[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 204 billion cubic feet of natural gas consumed in operations, 166 billion cubic feet in subsidiaries, 38 billion cubic feet in equity-accounted entities and excludes 14 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.

[c] Includes 133 billion cubic feet of gas (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010. Amounts by region are: 23 billion cubic feet in US; 27 billion cubic feet in South America; and 83 billion cubic feet in Rest of Asia.

[d] Includes 2,921 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[e] Includes 740 billion cubic feet relating to assets held for sale at 31 December 2010. Amounts by region are: 158 billion cubic feet in US; 205 billion cubic feet in South America; and 377 billion cubic feet in Rest of Asia.

[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[g] Includes 1 billion cubic feet of gas sales relating to production since classification of equity-accounted entities as held for sale.

[h] Includes 3 billion cubic feet of gas (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010.

[i] Includes 137 billion cubic feet of natural gas in respect of the 5.89% minority interest in TNK-BP.

[j] Includes 50 billion cubic feet relating to assets held for sale at 31 December 2010.

Movements in estimated net proved reserves continued

		million barrels
Bitumen[a]		2010
	Rest of North America	Total
Equity-accounted entities (BP share)		
At 1 January 2010		
Developed	–	–
Undeveloped	–	–
	–	–
Changes attributable to		
Revisions of previous estimates	–	–
Improved recovery	–	–
Purchases of reserves-in-place	–	–
Discoveries and extensions	179	179
Production	–	–
Sales of reserves-in-place	–	–
	179	179
At 31 December 2010		
Developed	–	–
Undeveloped	179	179
	179	179

[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.

Movements in estimated net proved reserves continued

million barrels of oil equivalent[b]

Total hydrocarbons[a]										2010
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2010										
Developed	680	91	3,514	135	596	613	–	455	612	6,696
Undeveloped	406	253	2,183	79	1,331	704	–	376	593	5,925
	1,086	344	5,697	214	1,927	1,317	–	831	1,205	12,621
Changes attributable to										
Revisions of previous estimates	18	2	(364)	(2)	(1)	(61)	–	(87)	(33)	(528)
Improved recovery	126	10	276	–	105	17	–	160	13	707
Purchases of reserves-in-place	–	38	22	–	–	–	–	41	–	101
Discoveries and extensions	36	1	207	2	4	257	–	–	–	507
Production[d e f]	(83)	(16)	(359)	(15)	(183)	(127)	–	(83)	(61)	(927)
Sales of reserves-in-place	(1)	–	(190)	(189)	–	(24)	–	–	–	(404)
	96	35	(408)	(204)	(75)	62	–	31	(81)	(544)
At 31 December 2010[g h]										
Developed	608	84	3,366	10	660	600	–	491	662	6,481
Undeveloped	574	295	1,923	–	1,192	779	–	371	462	5,596
	1,182	379	5,289	10	1,852	1,379	–	862	1,124	12,077
Equity-accounted entities (BP share)[i]										
At 1 January 2010										
Developed	–	–	–	–	623	–	2,645	377	–	3,645
Undeveloped	–	–	–	–	580	37	1,287	122	–	2,026
	–	–	–	–	1,203	37	3,932	499	–	5,671
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(20)	6	314	(19)	–	281
Improved recovery	–	–	–	–	83	–	269	2	–	354
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	179	4	–	–	–	–	183
Production[d e]	–	–	–	–	(64)[j k]	–	(354)	(73)	–	(491)
Sales of reserves-in-place	–	–	–	–	–	–	(4)	–	–	(4)
	–	–	–	179	3	6	225	(90)	–	323
At 31 December 2010[l]										
Developed	–	–	–	–	593	–	2,716	382	–	3,691
Undeveloped	–	–	–	179	613	43	1,441	27	–	2,303
	–	–	–	179	1,206[m]	43	4,157	409	–	5,994
Total subsidiaries and equity-accounted entities (BP share)[n]										
At 1 January 2010										
Developed	680	91	3,514	135	1,219	613	2,645	832	612	10,341
Undeveloped	406	253	2,183	79	1,911	741	1,287	498	593	7,951
	1,086	344	5,697	214	3,130	1,354	3,932	1,330	1,205	18,292
At 31 December 2010										
Developed	608	84	3,366	10	1,253	600	2,716	873	662	10,172
Undeveloped	574	295	1,923	179	1,805	822	1,441	398	462	7,899
	1,182	379	5,289	189	3,058	1,422	4,157	1,271	1,124	18,071

[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] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 78 million barrels of oil equivalent 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.

[d] Excludes NGLs from processing plants in which an interest is held of 29 thousand barrels of oil equivalent a day.

[e] Includes 35 million barrels of oil equivalent of natural gas consumed in operations, 28 million barrels of oil equivalent in subsidiaries, 7 million barrels of oil equivalent in equity-accounted entities and excludes 2 million barrels of oil equivalent of produced non-hydrocarbon components which meet regulatory requirements for sales.

[f] Includes 38 million barrels of oil equivalent (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010. Amounts by region are: 6 million barrels of oil equivalent in US; 11 million barrels of oil equivalent in South America; and 21 million barrels of oil equivalent in Rest of Asia.

[g] Includes 643 million barrels of NGLs. Also includes 526 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[h] Includes 197 million barrels of oil equivalent relating to assets held for sale at 31 December 2010. Amounts by region are: 34 million barrels of oil equivalent in US; 64 million barrels of oil equivalent in South America; and 99 million barrels of oil equivalent in Rest of Asia.

[i] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[j] Includes 2 million barrels of oil equivalent sold relating to production since classification of equity-accounted entities as held for sale.

[k] Includes 9 million barrels of oil equivalent (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010.

[l] Includes 18 million barrels of NGLs. Also includes 278 million barrels of oil equivalent in respect of the minority interest in TNK-BP.

[m] Includes 222 million barrels of oil equivalent relating to assets held for sale at 31 December 2010.

[n] Includes 1,311 million barrels of oil equivalent (197 million barrels of oil equivalent for subsidiaries and 1,114 million barrels of oil equivalent for equity-accounted entities) associated with properties currently held for sale where the disposal has not yet been completed.

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
										2012
	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 2012										
Subsidiaries										
Future cash inflows[a]	88,000	30,800	261,100	–	30,400	75,800	–	54,200	54,300	594,600
Future production cost[b]	24,600	10,400	117,000	–	10,700	17,200	–	14,000	19,000	212,900
Future development cost[b]	7,400	2,400	29,600	–	7,700	13,000	–	10,900	3,700	74,700
Future taxation[c]	35,200	11,700	40,700	–	6,300	17,500	–	6,900	8,400	126,700
Future net cash flows	20,800	6,300	73,800	–	5,700	28,100	–	22,400	23,200	180,300
10% annual discount[d]	10,900	2,400	40,100	–	2,700	10,900	–	8,300	11,800	87,100
Standardized measure of discounted future net cash flows[e]	9,900	3,900	33,700	–	3,000	17,200	–	14,100	11,400	93,200
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	9,500	49,400	–	203,600	24,400	–	286,900
Future production cost[b]	–	–	–	4,600	24,800	–	133,400	21,000	–	183,800
Future development cost[b]	–	–	–	2,400	5,500	–	16,600	1,900	–	26,400
Future taxation[c]	–	–	–	400	6,600	–	10,100	200	–	17,300
Future net cash flows	–	–	–	2,100	12,500	–	43,500	1,300	–	59,400
10% annual discount[d]	–	–	–	2,000	7,600	–	21,600	300	–	31,500
Standardized measure of discounted future net cash flows[g h]	–	–	–	100	4,900	–	21,900	1,000	–	27,900
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[i]	9,900	3,900	33,700	100	7,900	17,200	21,900	15,100	11,400	121,100

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	(34,600)	(8,300)	(42,900)
Development costs for the current year as estimated in previous year	13,800	3,700	17,500
Extensions, discoveries and improved recovery, less related costs	8,000	1,200	9,200
Net changes in prices and production cost	(14,600)	2,200	(12,400)
Revisions of previous reserves estimates	(16,200)	(800)	(17,000)
Net change in taxation	23,000	500	23,500
Future development costs	(7,100)	(1,100)	(8,200)
Net change in purchase and sales of reserves-in-place	(6,800)	(100)	(6,900)
Addition of 10% annual discount	11,600	2,800	14,400
Total change in the standardized measure during the year[j]	(22,900)	100	(22,800)

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[a] The marker prices used were Brent $111.13/bbl, Henry Hub $2.75/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 $900 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 $1,600 million in Russia.

[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] Includes future net cash flows for assets held for sale at 31 December 2012.

[j] Total change in the standardized measure during the year includes the effect of exchange rate movements.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves continued

										$ million
										2011
	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 2011										
Subsidiaries										
Future cash inflows[a]	97,900	36,400	332,900	100	39,100	82,100	–	59,200	53,900	701,600
Future production cost[b]	30,500	10,900	140,700	100	10,500	16,800	–	16,000	15,600	241,100
Future development cost[b]	8,500	2,700	32,300	–	7,600	13,200	–	9,600	3,200	77,100
Future taxation[c]	37,100	15,200	57,000	–	11,400	19,800	–	8,100	9,000	157,600
Future net cash flows	21,800	7,600	102,900	–	9,600	32,300	–	25,500	26,100	225,800
10% annual discount[d]	11,200	3,100	55,500	–	4,100	12,500	–	9,800	13,500	109,700
Standardized measure of discounted future net cash flows[e]	10,600	4,500	47,400	–	5,500	19,800	–	15,700	12,600	116,100
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	9,100	46,700	–	188,900	34,200	–	278,900
Future production cost[b]	–	–	–	3,100	21,500	–	123,800	30,100	–	178,500
Future development cost[b]	–	–	–	1,900	5,000	–	15,600	2,400	–	24,900
Future taxation[c]	–	–	–	900	5,900	–	9,600	200	–	16,600
Future net cash flows	–	–	–	3,200	14,300	–	39,900	1,500	–	58,900
10% annual discount[d]	–	–	–	2,800	8,700	–	19,000	600	–	31,100
Standardized measure of discounted future net cash flows[g] [h]	–	–	–	400	5,600	–	20,900	900	–	27,800
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	10,600	4,500	47,400	400	11,100	19,800	20,900	16,600	12,600	143,900

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	(30,900)	(5,700)	(36,600)
Development costs for the current year as estimated in previous year	12,800	2,900	15,700
Extensions, discoveries and improved recovery, less related costs	6,600	2,800	9,400
Net changes in prices and production cost	75,000	15,800	90,800
Revisions of previous reserves estimates	(22,000)	2,100	(19,900)
Net change in taxation	(18,200)	(1,400)	(19,600)
Future development costs	(10,800)	(2,700)	(13,500)
Net change in purchase and sales of reserves-in-place	(6,500)	(2,700)	(9,200)
Addition of 10% annual discount	10,000	1,500	11,500
Total change in the standardized measure during the year[i]	16,000	12,600	28,600

[a] The marker prices used were Brent $110.96/bbl, Henry Hub $4.12/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 $1,600 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 $1,600 million in Russia.

[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.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves continued

										$ million
										2010
	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 2010										
Subsidiaries										
Future cash inflows[a]	73,100	25,800	264,800	200	29,300	70,800	–	52,500	42,300	558,800
Future production cost[b]	25,700	9,800	111,400	200	6,800	14,000	–	13,400	12,800	194,100
Future development cost[b]	7,400	2,500	24,300	–	6,100	14,600	–	9,900	3,100	67,900
Future taxation[c]	19,900	8,100	41,900	–	8,200	14,100	–	7,000	6,200	105,400
Future net cash flows	20,100	5,400	87,200	–	8,200	28,100	–	22,200	20,200	191,400
10% annual discount[d]	9,800	2,300	45,500	–	3,300	11,900	–	8,200	10,300	91,300
Standardized measure of discounted future net cash flows[e]	10,300	3,100	41,700	–	4,900	16,200	–	14,000	9,900	100,100
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	9,700	45,500	–	110,500	31,000	–	196,700
Future production cost[b]	–	–	–	4,500	19,200	–	80,900	26,500	–	131,100
Future development cost[b]	–	–	–	2,000	4,300	–	11,000	2,800	–	20,100
Future taxation[c]	–	–	–	800	7,500	–	3,900	200	–	12,400
Future net cash flows	–	–	–	2,400	14,500	–	14,700	1,500	–	33,100
10% annual discount[d]	–	–	–	2,400	8,700	–	6,100	700	–	17,900
Standardized measure of discounted future net cash flows[g][h]	–	–	–	–	5,800	–	8,600	800	–	15,200
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[j]	10,300	3,100	41,700	–	10,700	16,200	8,600	14,800	9,900	115,300

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	(26,600)	(4,900)	(31,500)
Development costs for the current year as estimated in previous year	10,400	2,000	12,400
Extensions, discoveries and improved recovery, less related costs	9,600	1,600	11,200
Net changes in prices and production cost	52,800	1,900	54,700
Revisions of previous reserves estimates	(9,200)	200	(9,000)
Net change in taxation	(13,400)	(300)	(13,700)
Future development costs	(4,300)	(1,400)	(5,700)
Net change in purchase and sales of reserves-in-place	(1,500)	–	(1,500)
Addition of 10% annual discount	7,500	1,500	9,000
Total change in the standardized measure during the year[i]	25,300	600	25,900

[a] The marker prices used were Brent $79.02/bbl, Henry Hub $4.37/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 $1,200 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.

[j] Includes future net cash flows for assets held for sale at 31 December 2010.

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage. Figures include amounts attributable to assets held for sale.

Crude oil and natural gas production

The following table shows crude oil and natural gas production for the years ended 31 December 2012, 2011 and 2010.

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
2012	**86**	**23**	**390**	**1**	**28**	**202**	**–**	**139**	**27**	**896**
2011	113	32	453	2	39	190	–	138	25	992
2010	137	40	594	7	54	246	–	119	32	1,229
Natural gas[c]										million cubic feet per day
2012	**414**	**8**	**1,651**	**13**	**2,097**	**590**	**–**	**633**	**787**	**6,193**
2011	355	13	1,843	14	2,197	558	–	618	795	6,393
2010	472	15	2,184	202	2,544	556	–	574	785	7,332
Equity-accounted entities (BP share)										
Crude oil[b]										thousand barrels per day
2012	**–**	**–**	**–**	**–**	**80**	**–**	**863**	**217**	**–**	**1,160**
2011	–	–	–	–	90	–	865	210	–	1,165
2010	–	–	–	–	98	–	856	191	–	1,145
Natural gas[c]										million cubic feet per day
2012	**–**	**–**	**–**	**–**	**394**	**–**	**734**	**72**	**–**	**1,200**
2011	–	–	–	–	392	–	699	34	–	1,125
2010	–	–	–	–	399	–	640	30	–	1,069

[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 2012. 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 sum 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.

		Europe		North America		South America	Africa	Asia		Australasia	Total
		UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Number of productive wells at 31 December 2012											
Oil wells[a]	– gross	**158**	**58**	**2,451**	**55**	**3,870**	**590**	**20,970**	**1,951**	**13**	**30,116**
	– net	**90**	**24**	**987**	**28**	**2,133**	**434**	**9,409**	**392**	**2**	**13,499**
Gas wells[b]	– gross	**122**	**5**	**22,866**	**377**	**506**	**130**	**72**	**687**	**70**	**24,835**
	– net	**52**	**1**	**10,483**	**186**	**171**	**49**	**36**	**256**	**14**	**11,248**
Oil and natural gas acreage at 31 December 2012											Thousands of acres
Developed	– gross	**168**	**39**	**6,516**	**228**	**1,702**	**605**	**1,597**	**2,023**	**162**	**13,040**
	– net	**85**	**16**	**3,463**	**111**	**461**	**220**	**712**	**400**	**35**	**5,503**
Undeveloped[c]	– gross	**1,273**	**180**	**7,469**	**6,074**	**27,755**	**30,684**	**26,291**	**26,505**	**17,854**	**144,085**
	– net	**730**	**77**	**4,935**	**4,154**	**14,032**	**18,419**	**11,061**	**9,339**	**13,098**	**75,845**

[a] Includes approximately 3,762 gross (1,660 net) multiple completion wells (more than one formation producing into the same well bore).

[b] Includes approximately 2,557 gross (1,549 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.

[c] Undeveloped acreage includes leases and concessions.

Operational and statistical information continued

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		
2012										
Exploratory										
Productive	**–**	**0.3**	**17.1**	**–**	**5.8**	**2.3**	**14.7**	**–**	**–**	**40.2**
Dry	**0.2**	**–**	**0.6**	**–**	**1.0**	**0.5**	**5.0**	**–**	**–**	**7.3**
Development										
Productive	**1.6**	**–**	**317.8**	**–**	**78.9**	**17.7**	**552.5**	**43.1**	**–**	**1,011.6**
Dry	**–**	**–**	**–**	**–**	**–**	**1.0**	**–**	**9.5**	**–**	**10.5**
2011										
Exploratory										
Productive	0.4	–	34.1	–	4.4	2.1	16.7	1.0	0.2	58.9
Dry	–	–	2.1	–	0.2	–	7.2	0.3	0.3	10.1
Development										
Productive	1.7	–	199.4	–	101.3	16.0	582.0	45.1	–	945.5
Dry	–	–	0.2	–	3.0	2.7	–	0.4	–	6.3
2010										
Exploratory										
Productive	–	0.2	39.3	–	1.3	1.2	10.5	2.8	0.3	55.6
Dry	0.7	–	0.3	–	0.9	1.4	4.0	–	–	7.3
Development										
Productive	6.4	1.2	260.0	31.7	105.7	18.9	364.3	53.3	–	841.5
Dry	1.7	–	0.5	–	1.2	2.7	–	2.4	–	8.5

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 2012. 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 2012										
Exploratory										
Gross	**1.0**	**–**	**76.0**	**3.0**	**7.0**	**4.0**	**25.0**	**2.0**	**–**	**118.0**
Net	**0.5**	**–**	**19.2**	**1.5**	**1.6**	**1.4**	**12.0**	**0.2**	**–**	**36.4**
Development										
Gross	**6.0**	**5.0**	**633.0**	**55.0**	**30.0**	**25.0**	**207.0**	**69.0**	**13.0**	**1,043.0**
Net	**4.4**	**1.6**	**203.8**	**27.5**	**13.9**	**7.8**	**100.5**	**22.7**	**1.3**	**383.5**

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/ David J Jackson
Company Secretary
6 March 2013

Parent company financial statements of BP p.l.c.

Independent auditor's report to the members of BP p.l.c.

We have audited the parent company financial statements of BP p.l.c. for the year ended 31 December 2012 which comprise the company balance sheet, the company cash flow statement, the company statement of total recognized gains and losses and the related notes 1 to 13. The financial reporting framework that has been applied in their preparation is applicable law and United Kingdom accounting standards (United Kingdom generally accepted accounting practice).

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Respective responsibilities of directors and auditor

As explained more fully in the Statement of directors' responsibilities set out on page 178, the directors are responsible for the preparation of the parent company financial statements and for being satisfied that they give a true and fair view. Our responsibility is to audit and express an opinion on the parent company financial statements in accordance with applicable law and International Standards on Auditing (UK and Ireland). Those standards require us to comply with the Auditing Practices Board's Ethical Standards for Auditors.

Scope of the audit of the financial statements

An audit involves obtaining evidence about the amounts and disclosures in the financial statements sufficient to give reasonable assurance that the financial statements are free from material misstatement, whether caused by fraud or error. This includes an assessment of: whether the accounting policies are appropriate to the parent company's circumstances and have been consistently applied and adequately disclosed; the reasonableness of significant accounting estimates made by the directors; and the overall presentation of the financial statements. In addition, we read all the financial and non-financial information in the annual report to identify material inconsistencies with the audited parent company financial statements. If we become aware of any apparent material misstatements or inconsistencies we consider the implications for our report.

Opinion on financial statements

In our opinion the parent company financial statements:

- give a true and fair view of the state of the company's affairs as at 31 December 2012;
- have been properly prepared in accordance with applicable law and United Kingdom accounting standards (United Kingdom generally accepted accounting practice); and
- have been prepared in accordance with the requirements of the Companies Act 2006.

Opinion on other matters prescribed by the Companies Act 2006

In our opinion:

- the part of the Directors' remuneration report to be audited has been properly prepared in accordance with the Companies Act 2006; and
- the information given in the Directors' Report for the financial year for which the financial statements are prepared is consistent with the parent company financial statements.

Matters on which we are required to report by exception

We have nothing to report in respect of the following matters where the Companies Act 2006 requires us to report to you if, in our opinion:

- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or
- the parent company financial statements and the part of the Directors' remuneration report to be audited are not in agreement with the accounting records and returns; or
- certain disclosures of directors' remuneration specified by law are not made; or
- we have not received all the information and explanations we require for our audit.

Other matter

We have reported separately on the consolidated financial statements of BP p.l.c. for the year ended 31 December 2012. That report includes an emphasis of matter on the significant uncertainty over provisions and contingencies related to the Gulf of Mexico oil spill.

Ernst & Young LLP
Allister Wilson (Senior Statutory Auditor)
for and on behalf of Ernst & Young LLP, Statutory Auditor
London
6 March 2013

1. The maintenance and integrity of the BP p.l.c. website are the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

The parent company financial statements of BP p.l.c. on pages PC1–PC11 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Company balance sheet

At 31 December	Note	2012	$ million 2011
Fixed assets			
Investments			
Subsidiary undertakings	3	**133,420**	126,360
Associated undertakings	3	**2**	2
Total fixed assets		**133,422**	126,362
Current assets			
Debtors – amounts falling due:			
Within one year	4	**17,496**	17,698
After more than one year	4	**–**	38
Cash at bank and in hand		**9**	–
		17,505	17,736
Creditors – amounts falling due within one year	5	**2,604**	2,418
Net current assets		**14,901**	15,318
Total assets less current liabilities		**148,323**	141,680
Creditors – amounts falling due after more than one year	5	**4,487**	4,299
Net assets excluding pension plan deficit		**143,836**	137,381
Defined benefit pension plan deficit	6	**1,913**	2,088
Net assets		**141,923**	135,293
Represented by			
Capital and reserves			
Called-up share capital	7	**5,261**	5,224
Share premium account	8	**9,974**	9,952
Capital redemption reserve	8	**1,072**	1,072
Merger reserve	8	**26,509**	26,509
Own shares	8	**(280)**	(388)
Treasury shares	8	**(20,774)**	(20,935)
Share-based payment reserve	8	**1,604**	1,574
Profit and loss account	8	**118,557**	112,285
		141,923	135,293

The financial statements on pages PC2–PC11 were approved and signed by the group chief executive on 6 March 2013 having been duly authorized to do so by the board of directors:

R W Dudley Group Chief Executive

The parent company financial statements of BP p.l.c. on pages PC1–PC11 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Company cash flow statement

For the year ended 31 December	Note	2012	$ million 2011
Net cash outflow from operating activities	9	**(1,272)**	(3,799)
Servicing of finance and returns on investments			
Interest received		**183**	234
Interest paid		**(43)**	(47)
Dividends received		**13,515**	11,942
Net cash inflow from servicing of finance and returns on investments		**13,655**	12,129
Tax paid		**(2)**	(9)
Capital expenditure and financial investment			
Payments for fixed assets – investments		**(7,060)**	(3,719)
Proceeds from sale of fixed assets – investments		**–**	9
Net cash outflow for capital expenditure and financial investment		**(7,060)**	(3,710)
Equity dividends paid		**(5,294)**	(4,072)
Net cash inflow before financing		**27**	539
Financing			
Other share-based payment movements		**(18)**	(543)
Net cash outflow from financing		**(18)**	(543)
Increase (decrease) in cash	9	**9**	(4)

Company statement of total recognized gains and losses

For the year ended 31 December	Note	2012	$ million 2011
Profit for the year		**12,322**	11,484
Currency translation differences		**(98)**	164
Actuarial loss relating to pensions	6	**(573)**	(4,770)
Tax on actuarial loss relating to pensions	2	**–**	583
Total recognized gains and losses relating to the year		**11,651**	7,461

The parent company financial statements of BP p.l.c. on pages PC1–PC11 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Notes on financial statements

1. Accounting policies

Accounting standards

These accounts are prepared on a going concern basis and in accordance with the Companies Act 2006 and applicable UK accounting standards.

Accounting convention

The financial statements are prepared under the historical cost convention.

Foreign currency transactions

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. 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 profit for the year. Exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency branches are translated into US dollars are taken to a separate component of equity and reported in the statement of total recognized gains and losses.

Investments

Investments in subsidiaries and associated undertakings are recorded at cost. The company assesses investments for impairment whenever events or changes in circumstances indicate that the carrying value of an investment may not be recoverable. If any such indication of impairment exists, the company makes an estimate of its recoverable amount. Where the carrying amount of an investment exceeds its recoverable amount, the investment is considered impaired and is written down to its recoverable amount.

Share-based payments

Equity-settled transactions

The cost of equity-settled transactions with employees of the company and other members of the group 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.

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

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 the statement of total recognized gains and losses 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. The surplus or deficit, net of taxation thereon, is presented separately above the total for net assets on the face of the balance sheet.

The BP Pension Fund is operated in a way that does not allow the individual participating employing companies in the pension fund to identify their share of the underlying assets and liabilities of the fund, and hence the company recognizes the full defined benefit pension plan surplus or deficit in its balance sheet.

Deferred taxation

Deferred tax is recognized in respect of all timing differences that have originated but not reversed at the balance sheet date where transactions or events have occurred at that date that will result in an obligation to pay more, or a right to pay less, tax in the future.

Deferred tax assets are recognized only to the extent that it is considered more likely than not that there will be suitable taxable profits from which the underlying timing differences can be deducted.

Deferred tax is measured on an undiscounted basis at the tax rates that are expected to apply in the periods in which timing differences reverse, based on tax rates and laws enacted or substantively enacted at the balance sheet date.

Use of estimates

The preparation of accounts in conformity with generally accepted accounting practice requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the accounts and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from these estimates.

2. Taxation

Tax charge included in the statement of total recognized gains and losses	2012	2011
		$ million
Deferred tax		
Origination and reversal of timing differences in the current year	–	(583)
This comprises:		
Actuarial loss relating to pensions and other post-retirement benefits	–	(583)

Deferred tax		
Net deferred tax liability (asset)	–	–
Analysis of movements during the year		
At 1 January	–	410
Exchange adjustments	–	34
Charge for the year on ordinary activities	–	139
Credit for the year in the statement of total recognized gains and losses	–	(583)
At 31 December	–	–

At 31 December 2012, deferred tax assets of $97 million on pensions (2011 $559 million) and $82 million on other timing differences (2011 $91 million) were not recognized as it is not considered more likely than not that suitable taxable profits will be available in the company from which the future reversal of the underlying timing differences can be deducted. It is anticipated that the reversal of these timing differences will benefit other group companies in the future.

3. Fixed assets – investments

				$ million
	Subsidiary undertakings	Associated undertakings		
	Shares	Shares	Loans	Total
Cost				
At 1 January 2012	**126,434**	**2**	**2**	**126,438**
Additions	**7,060**	**–**	**–**	**7,060**
At 31 December 2012	**133,494**	**2**	**2**	**133,498**
Amounts provided				
At 1 January 2012	**74**	**–**	**2**	**76**
At 31 December 2012	**74**	**–**	**2**	**76**
Cost				
At 1 January 2011	122,723	2	2	122,727
Additions	3,719	–	–	3,719
Disposals	(8)	–	–	(8)
At 31 December 2011	126,434	2	2	126,438
Amounts provided				
At 1 January 2011	74	–	2	76
At 31 December 2011	74	–	2	76
Net book amount				
At 31 December 2012	**133,420**	**2**	**–**	**133,422**
At 31 December 2011	126,360	2	–	126,362

The more important subsidiary undertakings of the company at 31 December 2012 and the percentage holding of ordinary share capital (to the nearest whole number) are set out below. A complete list of investments in subsidiary undertakings, joint ventures and associated undertakings will be attached to the company's annual return made to the Registrar of Companies.

Subsidiary undertakings	%	Country of incorporation	Principal activities
International			
BP Corporate Holdings	100	England & Wales	Investment holding
BP Global Investments	100	England & Wales	Investment holding
BP International	100	England & Wales	Integrated oil operations
BP Shipping	100	England & Wales	Shipping
Burmah Castrol	100	Scotland	Lubricants
South Africa			
BP Southern Africa	75	South Africa	Refining and marketing
US			
BP Holdings North America	100	England & Wales	Investment holding

The carrying value of BP International in the accounts of the company at 31 December 2012 was $62.63 billion (2011 $62.63 billion).

The parent company financial statements of BP p.l.c. on pages PC1–PC11 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

4. Debtors

	2012		2011	
				$ million
	Within 1 year	**After 1 year**	Within 1 year	After 1 year
Group undertakings	**17,496**	**–**	17,695	38
Other	**–**	**–**	3	–
	17,496	**–**	17,698	38

The carrying amounts of debtors approximate their fair value.

5. Creditors

	2012		2011	
				$ million
	Within 1 year	**After 1 year**	Within 1 year	After 1 year
Group undertakings	**2,376**	**4,274**	2,334	4,264
Accruals and deferred income	**27**	**38**	28	35
Other creditors	**201**	**175**	56	–
	2,604	**4,487**	2,418	4,299

The carrying amounts of creditors approximate their fair value.

The maturity profile of the financial liabilities included in the balance sheet at 31 December is shown in the table below. These amounts are included within Creditors – amounts falling due after more than one year, and are denominated in US dollars.

Amounts falling due after one year include $4,236 million payable to a group undertaking. This amount is subject to interest payable quarterly at LIBOR plus 55 basis points.

Other creditors includes an amount of $350 million payable in respect of the settlement with the US Securities and Exchange Commission described in Note 2 of the consolidated financial statements.

	2012	2011
		$ million
Due within		
1 to 2 years	**230**	49
2 to 5 years	**17**	14
More than 5 years	**4,240**	4,236
	4,487	4,299

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6. Pensions

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. With effect from 1 April 2010, BP closed its UK plan to new joiners other than some of those joining the North Sea business. The plan remains open to those employees who joined BP on or before 31 March 2010. The majority of new joiners in the UK have the option to join a defined contribution plan.

The obligation and cost of providing the pension benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2012. The principal plans are subject to a formal actuarial valuation every three years in the UK. The most recent formal actuarial valuation of the main UK pension plan was as at 31 December 2011.

The material financial assumptions used for estimating the benefit obligations of the plans are set out below. The assumptions used to evaluate accrued pensions at 31 December in any year are used to determine pension expense for the following year, that is, the assumptions at 31 December 2012 are used to determine the pension liabilities at that date and the pension cost for 2013.

Financial assumptions			%
	2012	2011	2010
Expected long-term rate of return	**6.9**	7.0	7.3
Discount rate for plan liabilities	**4.4**	4.8	5.5
Rate of increase in salaries	**4.9**	5.1	5.4
Rate of increase for pensions in payment	**3.1**	3.2	3.5
Rate of increase in deferred pensions	**3.1**	3.2	3.5
Inflation	**3.1**	3.2	3.5

Our discount rate assumption is based on third-party AA corporate bond indices and we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumption is based on the difference between the yields on index-linked and fixed-interest long-term government bonds. The inflation assumptions are used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions.

Our assumption for the rate of increase in salaries is based on our inflation assumption plus an allowance for expected long-term real salary growth. This includes allowance for promotion-related salary growth of 0.7%.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. The mortality assumptions reflect best practice in the UK, 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.

Mortality assumptions			
	2012	2011	2010
Life expectancy at age 60 for a male currently aged 60	**27.7**	27.6	26.1
Life expectancy at age 60 for a male currently aged 40	**30.6**	30.5	29.1
Life expectancy at age 60 for a female currently aged 60	**29.4**	29.3	28.7
Life expectancy at age 60 for a female currently aged 40	**32.1**	32.0	31.6

The market values of the various categories of asset held by the pension plan at 31 December are set out below.

						$ million
		2012		2011		2010
	Expected long-term rate of return %	**Market value $ million**	Expected long-term rate of return %	Market value $ million	Expected long-term rate of return %	Market value $ million
Equities	**8.0**	**19,612**	8.0	17,202	8.0	17,703
Bonds[a]	**3.8**	**4,885**	4.4	4,141	5.1	3,128
Property[b]	**6.5**	**1,783**	6.5	1,710	6.5	1,412
Cash	**0.9**	**1,066**	1.7	534	1.4	369
	6.9	**27,346**	7.0	23,587	7.3	22,612
Present value of plan liabilities		**29,259**		25,675		20,742
(Deficit) surplus in the plan		**(1,913)**		(2,088)		1,870

[a] Bonds held are all denominated in sterling.
[b] Property held is all located in the United Kingdom.

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6. Pensions continued

		$ million
	2012	2011
Analysis of the amount charged to operating profit		
Current service cost[a]	**477**	380
Settlement, curtailment and special termination benefits[b]	**(1)**	3
Payments to defined contribution plans	**14**	5
Total operating charge[c]	**490**	388
Analysis of the amount credited (charged) to other finance income		
Expected return on pension plan assets	**1,680**	1,773
Interest on pension plan liabilities	**(1,249)**	(1,240)
Other finance income	**431**	533
Analysis of the amount recognized in statement of total recognized gains and losses		
Actual return less expected return on pension plan assets	**989**	(1,976)
Change in assumptions underlying the present value of the plan liabilities	**(1,446)**	(2,710)
Experience gains and losses arising on the plan liabilities	**(116)**	(84)
Actuarial loss recognized in statement of total recognized gains and losses	**(573)**	(4,770)

		$ million
	2012	2011
Movements in benefit obligation during the year		
Benefit obligation at 1 January	**25,675**	20,742
Exchange adjustment	**1,313**	(204)
Current service cost[a]	**477**	380
Interest cost	**1,249**	1,240
Transfers of plans from other group companies[d]	**–**	1,671
Curtailments	**(8)**	–
Disposals	**(10)**	–
Special termination benefits	**7**	3
Contributions by plan participants	**39**	33
Benefit payments (funded plans)[e]	**(1,038)**	(980)
Benefit payments (unfunded plans)[e]	**(7)**	(4)
Actuarial loss on obligation	**1,562**	2,794
Benefit obligation at 31 December	**29,259**	25,675
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	**23,587**	22,612
Exchange adjustment	**1,215**	(41)
Expected return on plan assets[a f]	**1,680**	1,773
Contributions by plan participants[g]	**39**	33
Contributions by employers (funded plans)	**884**	423
Transfers of plans from other group companies[d]	**–**	1,743
Disposals	**(10)**	–
Benefit payments (funded plans)[e]	**(1,038)**	(980)
Actuarial gain (loss) on plan assets[f]	**989**	(1,976)
Fair value of plan assets at 31 December[h]	**27,346**	23,587
Deficit at 31 December	**(1,913)**	(2,088)

[a] The costs of managing the plan's investments are treated as being part of the investment return, the costs of administering our pensions plan benefits are included in current service cost.

[b] The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.

[c] Included within production and manufacturing expenses and distribution and administration expenses.

[d] Transfer of the Burmah Castrol Pension Fund and the Lubricants UK Limited pension plan.

[e] The benefit payments amount shown above comprises $1,022 million benefits plus $16 million of plan expenses incurred in the administration of the benefit.

[f] The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial gain or loss on the plan assets as disclosed above.

[g] The contributions by plan participants for the UK mostly comprise contributions made under salary sacrifice arrangements.

[h] Reflects $27,220 million of assets held in the BP Pension Fund (2011 $23,482 million) and $94 million held in the BP Global Pension Trust (2011 $75 million), with $32 million representing the company's share of Merchant Navy Officers Pension Fund (2011 $30 million).

6. Pensions continued

		$ million
	2012	2011
Reconciliation of plan deficit to balance sheet		
Deficit at 31 December	**(1,913)**	(2,088)
Deferred tax	**–**	–
	(1,913)	(2,088)
Represented by		
Liability recognized on balance sheet	**(1,913)**	(2,088)
	(1,913)	(2,088)

The aggregate level of employer contributions into the BP Pension Fund in 2013 is expected to be $496 million.

					$ million
	2012	2011	2010	2009	2008
History of (deficit) surplus and of experience gains and losses					
Benefit obligation at 31 December	**29,259**	25,675	20,742	19,882	15,414
Fair value of plan assets at 31 December	**27,346**	23,587	22,612	20,953	16,930
(Deficit) surplus	**(1,913)**	(2,088)	1,870	1,071	1,516
Experience gains and losses on plan liabilities					
Amount ($ million)	**(116)**	(84)	12	(146)	(65)
Percentage of benefit obligation	**0%**	0%	0%	(1%)	0%
Actual return less expected return on pension plan assets					
Amount ($ million)	**989**	(1,976)	1,479	1,634	(6,533)
Percentage of plan assets	**4%**	(8%)	7%	8%	(39%)
Actuarial (loss) gain recognized in statement of total recognized gains and losses					
Amount ($ million)	**(573)**	(4,770)	457	(585)	(5,122)
Percentage of benefit obligation	**(2%)**	(19%)	2%	(3%)	(33%)
Cumulative amount recognized in statement of total recognized gains and losses	**(6,578)**	(6,005)	(1,235)	(1,692)	(1,107)

7. Called-up share capital

The allotted, called-up and fully paid share capital at 31 December was as follows:

	2012		2011	
Issued	**Shares (thousand)**	**$ million**	Shares (thousand)	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9
		21		21
Ordinary shares of 25 cents each				
At 1 January	**20,813,410**	**5,203**	20,647,160	5,162
Issue of new shares for the scrip dividend programme	**138,406**	**35**	165,601	41
Issue of new shares for employee share schemes[b]	**7,343**	**2**	649	–
31 December	**20,959,159**	**5,240**	20,813,410	5,203
		5,261		5,224

[a] The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.

[b] The nominal value of new shares issued for the employee share plans in 2011 amounted to $162,000. Consideration received relating to the issue of new shares for employee share plans amounted to $46 million (2011 $4 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.

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8. Capital and reserves

$ million

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Own shares	Treasury shares	Share-based payment reserve	Profit and loss account	Total
At 1 January 2012	5,224	9,952	1,072	26,509	(388)	(20,935)	1,574	112,285	135,293
Currency translation differences	–	–	–	–	–	–	–	(98)	(98)
Actuarial loss on pensions (net of tax)	–	–	–	–	–	–	–	(573)	(573)
Share-based payments	2	57	–	–	108	161	30	(85)	273
Profit for the year	–	–	–	–	–	–	–	12,322	12,322
Dividends	35	(35)	–	–	–	–	–	(5,294)	(5,294)
At 31 December 2012	5,261	9,974	1,072	26,509	(280)	(20,774)	1,604	118,557	141,923

$ million

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Own shares	Treasury shares	Share-based payment reserve	Profit and loss account	Total
At 1 January 2011	5,183	9,987	1,072	26,509	(126)	(21,085)	1,585	108,794	131,919
Currency translation differences	–	–	–	–	–	–	–	164	164
Actuarial loss on pensions (net of tax)	–	–	–	–	–	–	–	(4,187)	(4,187)
Share-based payments	–	6	–	–	(262)	150	(11)	102	(15)
Profit for the year	–	–	–	–	–	–	–	11,484	11,484
Dividends	41	(41)	–	–	–	–	–	(4,072)	(4,072)
At 31 December 2011	5,224	9,952	1,072	26,509	(388)	(20,935)	1,574	112,285	135,293

As a consolidated income statement is presented for the group, a separate income statement for the parent company is not required to be published.

The profit and loss account reserve includes $24,107 million (2011 $24,107 million), the distribution of which is limited by statutory or other restrictions.

The accounts for the year ended 31 December 2012 do not reflect the dividend announced on 5 February 2013 and payable in March 2013; this will be treated as an appropriation of profit in the year ended 31 December 2013.

9. Cash flow

Notes on cash flow statement

$ million

	2012	2011
Reconciliation of net cash flow to movement of funds		
Increase (decrease) in cash	9	(4)
Movement of funds	9	(4)
Net cash at 1 January	–	4
Net cash at 31 December	9	–
Notes on cash flow statement		
(a) Reconciliation of operating profit to net cash (outflow) inflow from operating activities	2012	2011
Operating profit	11,936	11,136
Net operating charge for pensions and other post-retirement benefits, less contributions	(414)	(117)
Dividends, interest and other income	(13,758)	(12,132)
Share-based payments	350	528
Decrease (increase) in debtors	240	(3,253)
Increase in creditors	374	39
Net cash outflow from operating activities	(1,272)	(3,799)

$ million

(b) Analysis of movements of funds	At 1 January 2012	Cash flow	At 31 December 2012
Cash at bank	–	9	9

The parent company financial statements of BP p.l.c. on pages PC1–PC11 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

10. Contingent liabilities

The parent company has issued guarantees under which amounts outstanding at 31 December 2012 were $45,400 million (2011 $41,847 million), of which $45,370 million (2011 $40,449 million) related to guarantees in respect of subsidiary undertakings, including $44,629 million (2011 $39,708 million) in respect of borrowings by its subsidiary undertakings, and $30 million (2011 $30 million) in respect of liabilities of other third parties.

11. Share-based payments

Effect of share-based payment transactions on the company's result and financial position

		$ million
	2012	2011
Total expense recognized for equity-settled share-based payment transactions	**669**	579
Total expense recognized for cash-settled share-based payment transactions	**5**	5
Total expense recognized for share-based payment transactions	**674**	584
Closing balance of liability for cash-settled share-based payment transactions	**12**	12
Total intrinsic value for vested cash-settled share-based payments	**–**	1

Information on the company's share-based payment schemes is provided in Note 40 to the consolidated financial statements.

12. Auditor's remuneration

Note 16 to the consolidated financial statements provides details of the remuneration of the company's auditor on a group basis.

13. Directors' remuneration

		$ million
Remuneration of directors	**2012**	2011
Total for all directors		
Emoluments	**12**	10
Gains made on the exercise of share options	**–**	–
Amounts awarded under incentive schemes	**3**	1

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 cash bonuses awarded for the year. There was no compensation for loss of office in 2012 (2011 nil and 2010 $3 million).

Pension contributions

During 2012, two executive directors participated in a non-contributory pension scheme established for UK staff 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 2012.

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 127-145.

The parent company financial statements of BP p.l.c. on pages PC1–PC11 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Cross reference to Form 20-F

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This document is part of BP's corporate reporting suite. We report on our financial and operating performance, sustainability performance and also on global energy trends and projections.

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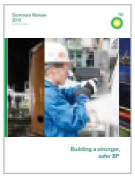

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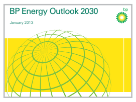

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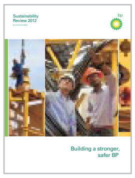

Sustainability Review 2012
A summary of our sustainability reporting or find additional information online.
Publishes March.
bp.com/sustainability

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Five-year financial and operating data in PDF or Excel format.
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