BP PLC
Form 20-F
March 06, 2014
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 20-F

(Mark One)

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

OR

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

For the fiscal year ended 31 December 2013

OR

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

OR

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

Commission file number: 1-6262

BP p.l.c.

(Exact name of Registrant as specified in its charter)

England and Wales

(Jurisdiction of incorporation or organization)

1 St James s Square, London SW1Y 4PD

United Kingdom

(Address of principal executive offices)

Dr Brian Gilvary

BP p.l.c.

1 St James s Square, London SW1Y 4PD

United Kingdom

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(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

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

Title of each class	Name of each exchange on which registered
Ordinary Shares of 25c each	New York Stock Exchange*
Floating Rate Guaranteed Notes due 2014	New York Stock Exchange
Floating Rate Guaranteed Notes due May 2015	New York Stock Exchange
Floating Rate Guaranteed Notes due November 2015	New York Stock Exchange
Floating Rate Guaranteed Notes due 2016	New York Stock Exchange
Floating Rate Guaranteed Notes due May 2018	New York Stock Exchange
Floating Rate Guaranteed Notes due September 2018	New York Stock Exchange
Floating Rate Guaranteed Notes due 2019	New York Stock Exchange
3.625% Guaranteed Notes due 2014	New York Stock Exchange
1.700% Guaranteed Notes due 2014	New York Stock Exchange

0.700% Guaranteed Notes due 2015	**New York Stock Exchange**
3.875% Guaranteed Notes due 2015	**New York Stock Exchange**
3.125% Guaranteed Notes due 2015	**New York Stock Exchange**
2.248% Guaranteed Notes due 2016	**New York Stock Exchange**
3.200% Guaranteed Notes due 2016	**New York Stock Exchange**
1.375% Guaranteed Notes due 2017	**New York Stock Exchange**
1.375% Guaranteed Notes due 2018	**New York Stock Exchange**
2.241% Guaranteed Notes due 2018	**New York Stock Exchange**
1.846% Guaranteed Notes due 2017	**New York Stock Exchange**
4.750% Guaranteed Notes due 2019	**New York Stock Exchange**
2.237% Guaranteed Notes due 2019	**New York Stock Exchange**
4.500% Guaranteed Notes due 2020	**New York Stock Exchange**
4.742% Guaranteed Notes due 2021	**New York Stock Exchange**
3.561% Guaranteed Notes due 2021	**New York Stock Exchange**
2.500% Guaranteed Notes due 2022	**New York Stock Exchange**
3.245% Guaranteed Notes due 2022	**New York Stock Exchange**
2.750% Guaranteed Notes due 2023	**New York Stock Exchange**
3.994% Guaranteed Notes due 2023	**New York Stock Exchange**
3.814% Guaranteed Notes due 2024	**New York Stock Exchange**

* Not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

Table of Contents

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

None

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

None

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

Ordinary Shares of 25c each	20,426,632,529
Cumulative First Preference Shares of £1 each	7,232,838
Cumulative Second Preference Shares of £1 each	5,473,414

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ¨ No x

Note Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).* Yes ¨ No ¨

* This requirement does not apply to the registrant in respect of this filing.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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

International Financial Reporting

Standards as issued by the

U.S. GAAP ¨ International Accounting Standards Board x Other ¨

If Other has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 ¨ Item 18 ¨

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

Table of Contents

Annual Report and

Form 20-F 2013

bp.com/annualreport

Building a stronger,

safer BP

Table of Contents

Table of Contents

BP in 2013

Our actions continue to make BP stronger and safer. We are growing shareholder returns through operational efficiency and financial discipline. We report on our progress here.

Table of Contents

Information about this report

Frequent abbreviations

ADR

American depositary receipt.

ADS

American depositary share.

Barrel (bbl)

159 litres, 42 US gallons.

bcf

Billion cubic feet.

bcf/d

Billion cubic feet per day.

bcfe

Billion cubic feet equivalent.

bcma

Billion cubic metres per annum.

b/d

Barrels per day.

boe

Barrels of oil equivalent.

GAAP

Generally accepted accounting practice.

Gas

Natural gas.

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 2013. A cross reference to Form 20-F requirements is included on page 282.

The *BP Annual Report and 20-F 2013* reflects a number of significant changes in regulations in the UK. The most significant change is the requirement to produce a new strategic report that replaces the previous business review. The regulations require certain new disclosure to be included in the strategic report including a description of company s strategy and business model we have included a more focused and graphical presentation of BP s strategy and business model in this report, compared with the 2012 report.

This document contains the Strategic report on pages 1-58 and the inside cover (Who we are section) and the Directors report on pages 59-80, 109-114, 116, 200-223 and 235-280. The Strategic report and the Directors report together include the management report required by DTR 4.1 of the UK Financial Conduct Authority s Disclosure and Transparency Rules. The Directors remuneration report is on pages 81-108. The consolidated financial statements of the group are on pages 115-199 and the corresponding reports of the auditor are on pages 120-121.

BP Annual Report and Form 20-F 2013 and *BP Strategic Report 2013* (comprising the Strategic report and supplementary information) 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 2013* or *BP Strategic Report 2013* (comprising the Strategic report and supplementary information), forms any part of those documents. References in this document to other documents on the BP website, such as the *BP Energy Outlook,* are included as an aid to their location and are not incorporated by reference into this document.

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

Hydrocarbons

Liquids 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.

mmcf

Million cubic feet.

mmcf/d

Million cubic feet per day.

MW

Megawatt.

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 non-controlling 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 (NYSE) in the form of ADSs (see page 274 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 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:

Aral

ARCO

BP

Castrol

Castrol EDGE

Field of the Future

Fluid Strength Technology

Hummingbird

LoSal

Project 20K

SaaBre

Veba Combi-Cracking (VCC)

Permasense is a trade mark of Permasense Limited.

Pick n Pay is a registered trademark of
Pick n Pay Stores Limited.

NGLs

Natural gas liquids.

PSA

Production-sharing agreement.

RC

Replacement cost.

SEC

The United States Securities and Exchange Commission.

Therm

100,000 British thermal units.

Tonne

2,204.6 pounds.

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 .

Table of Contents

Table of Contents

BP at a glance

Table of Contents

Table of Contents

BP around the world

Table of Contents

Table of Contents

Chairman s letter

10-year dividend history

UK (pence per ordinary share)

US (cents per ADS)

One ADS represents six 25 cent ordinary shares.

Dear fellow shareholder,

In 2013 BP continued the programme of renewal we began following the crisis of 2010. The measures taken to secure and reshape the group are taking hold. As this report shows, BP is stronger and safer as a result.

Change within the group has taken place against the backdrop of a rapidly evolving world. The energy landscape is developing at pace, for example, the growth of shale gas in the US. But the long-term supply challenge has not gone away. More energy is required to meet the needs and aspirations of a rising global population. The *BP Energy Outlook* projects an average increase in energy demand of 1.5% per year through to 2035. That s like adding the needs of a country twice the size of the US over the next twenty years.

We are also seeing that society has ever higher expectations of business. This is reflected in the increasing scrutiny placed on the commercial sector, particularly by politicians and the media. Companies must work hard to maintain people s trust and respect.

Shareholders expectations are shifting too, particularly in the extractive industries sector. Some investors feel that international oil companies have spent too much for too little return. A decade of mergers and acquisitions in our industry has generated little production growth. Capital expenditure has increased but profit margins have been squeezed. Rightly, shareholders expect better returns.

The board recognizes this changing world and the importance of our response. Throughout 2013 we gave close attention to strategy, project appraisal and capital discipline, working with Bob Dudley and his team to ensure the group spends its money wisely. BP s strategy is rooted in three imperatives: clear priorities, a quality portfolio and distinctive capabilities.

Our first clear priority is to run safe and reliable operations. We must also make disciplined financial choices, selecting the smart options that can help meet demand and generate value. Furthermore, we must be competitive in how we execute our projects.

Our quality portfolio, which is at the core of our strategy, is the result of the choices we make. It contains assets that enable us to play to our areas of greatest strength, from exploration to high-value upstream projects particularly deepwater operations, giant fields and gas value chains and high-quality downstream businesses.

To these assets and activities we apply our distinctive capabilities the expertise of our people, advanced technology and the ability to build the strong relationships required to access resources and deliver complex projects.

In all of this, we are focused on value before volume. In other words we don t simply chase production for the sake of it, rather we choose projects where we can generate the most value through our production.

We know we must be disciplined, sticking to clear limits on capital expenditure, and balancing rewards for shareholders today with the long-term capital investment required for tomorrow. Safety and strong governance must underpin everything we do.

2013 was a busy and successful year for BP, with progress in our underlying operations. Our growing confidence was reflected in the dividend increase announced in October

Table of Contents

Board performance

For information about the board and its committees see page 71.

Remuneration

For information about our approach to executive directors remuneration see page 20.

Top: Members of BP s safety, ethics and environment assurance committee (SEEAC) visited Canada to see the oil sands operations at the Sunrise project site and meet local community leaders and staff.

Bottom: Members of SEEAC travelled to the Gelsenkirchen refinery in Germany to speak with apprentices and control room operators about risk management and processes.

2013 the third increase in two years. We also returned value to shareholders through the $8-billion share repurchase programme announced in March 2013. Additional distributions are planned as we make further divestments to reshape our portfolio. The milestones set for 2014 will be an important measure of progress and your board is monitoring this closely.

I am particularly pleased that in 2013 we completed our transaction with Rosneft, closing one chapter in Russia and opening another. This is an important investment with the potential to create substantial value for BP over the years to come.

2013 also saw the shocking attack at the In Amenas facility in Algeria. Our thoughts remain with the families and friends of those who died. The response of management to this tragedy was strong and the board acted positively and promptly.

We continue to address uncertainty in the US. In 2013, we once again met our responsibilities to the region by paying legitimate claims arising from the 2010 accident and oil spill in the Gulf of Mexico. And we met our responsibilities to shareholders by challenging and resisting any attempt to take advantage of BP with claims that are not legitimate. We will fight through the courts until matters are resolved properly, however long that takes. In the meantime, the board is working to ensure that BP is not distracted from growing the business and creating shareholder value.

Boards set the tone and values that shape performance and behaviour over the long term. An effective board creates an enduring framework within which management can lead. Having been through challenging times, the BP board has grown into a strong team with experienced non-executives drawn from relevant industries. This year, more than ever, they have been out to see BP s operations for themselves, from India to Indiana. We continue to be assisted on geopolitical matters by the international advisory board.

Our approach to governance has enabled us to focus on critical strategic issues, with our board committees taking on the many oversight and compliance matters that require attention.

Remuneration continues to be a board matter of particular importance to shareholders, with executive pay policy now subject to a vote at the annual general meeting. BP has a record of ensuring there are clear links between strategy, performance and remuneration. This will continue.

I believe diversity helps to strengthen the effectiveness of a board. We plan succession well ahead and are developing a pipeline of potential board candidates. We are committed to progress and finding the right people for our board.

I would like to end by thanking you, our shareholders, for your continued support. I also want to acknowledge the people who drive your company forward every working day. From Bob Dudley and his management team to employees across the business; our people are doing a great job of transforming BP. Their hard work has moved us forward, with the promise of more to come.

Carl-Henric Svanberg

Chairman

6 March 2014

Table of Contents

Group chief executive s letter

95.3%

2013 refining availability.

129%

Reserves replacement ratio, excluding the impact of acquisitions and divestments.

See footnote b on page 14.

Dear fellow shareholder,

For BP, 2013 was a year of good progress in building a safer, stronger and better performing company. We made new discoveries, started up new operations, strengthened our portfolio and secured a new future in Russia. We also maintained our investment in the US while standing up for what we believe to be right.

Within BP, sadly, 2013 will also be remembered for the terrorist attack in Algeria in January, when four staff members and 36 colleagues from other companies were killed. Those who died had many friends in BP and our thoughts remain with their loved ones, and with those who survived that terrible ordeal. I was proud of the way people in BP responded with great compassion, but also with great fortitude.

This report contains a wealth of information on our performance. I would like to draw out a few of the year s highlights, all of which demonstrate how we are implementing our strategy, with its emphasis on clear priorities, a quality portfolio and distinctive capabilities.

Clear priorities: safety, capital discipline, project execution

The first of our priorities is to run safe and reliable operations. In 2013 we made good progress overall, but unfortunately we also suffered two driving-related fatalities as well as the loss of the four employees murdered at In Amenas. Our thoughts are with those who have been bereaved. We will implement the lessons learned.

In terms of general safety performance, however, we saw some encouraging progress. The number of tier 1 process safety events the most significant incidents fell to 20 from 43 in 2012 and 74 in 2011. We are definitely heading in the right direction, but there is always more to do and we remain vigilant.

We also saw improvements in measures that reflect the underlying health of our business. For example, in upstream BP-operated plant efficiency[a] reached 88%, and refining availability in downstream averaged 95.3% the highest level for 10 years. These numbers reinforce my view that safety and value have the same roots: systematic, disciplined operations, undertaken by people who respect each other and work as one team.

In terms of capital discipline, in 2013 we invested $24.6 billion[b], which kept us within our $25-billion limit, and we expect to keep capital expenditure broadly the same in 2014. We know we have to invest wisely so we maintain our shareholders trust.

Turning to project execution, we saw three upstream major projects start up in 2013 in the Gulf of Mexico, Angola and Australia. Three more followed closely in the first months of 2014 the Chirag oil project in Azerbaijan and the Mars B and Na Kika Phase 3 projects in the Gulf of Mexico.

Quality portfolio

Beyond these start-ups, we extended our portfolio as a platform for growth in several other ways.

For example, we grew our exploration position by participating in seven potentially commercial discoveries, in Angola, Brazil, Egypt, India and the Gulf of Mexico. We also drilled 17 exploration wells, more than in the previous two years put together. BP has built up great skills in finding oil and gas and we are seeing the results of investing in our explorers.

And in the US lower 48 which excludes Alaska and Hawaii we intend to create a separate BP business to manage our onshore oil and gas assets, which we believe will help to unlock the significant value associated with our extensive resource position there.

Our strategy

For more on our strategic priorities and

longer-term objectives see page 13.

Our reserves replacement ratio was 129% of production. When we include the net growth in our Russian portfolio as a result of the change of our holdings, the reserves replacement ratio on a combined basis was 199%.[c]

In the Downstream, we completed the commissioning of all major units for the Whiting refinery. This landmark modernization programme, our fourth major project start-up in 2013, is turning what began as a 19th century plant into a truly 21st century one. It is now able to compete strongly by processing a wide range of crudes, including heavy oil from Canada.

Top: Bob Dudley and Iraq Oil Minister Abdul Karim Al Luaibi (right) being shown the first meter to be installed on one of the wells in Kirkuk. In October BP signed an agreement with the government of Iraq on providing technical assistance relating to the Kirkuk oil field.

More generally, our Downstream business has transformed its shape over the last five years. In the US, we have sold two facilities and we now have three modern refineries that are well configured and well connected to important markets. In lubricants, 40% of revenue now comes from our premium brands. In petrochemicals, we are also focusing on high-growth regions and new technologies.

Distinctive capabilities

Bottom: Investors see how BP manages the risks of deepwater drilling at a field trip in Houston. They tested our well simulator which gives rig operators a better understanding of both prevention and response techniques.

New acetic acid and ethylene technologies announced by the petrochemical team in 2013 are among a series of innovations we have developed in support of our exploration, production, refining and marketing activities. These include advanced seismic imaging capacity using one of the world s largest civilian supercomputers enhanced oil recovery techniques and leading lubricant processes.

Our technologies are complemented by the capabilities of our people, which we continue to deepen through training and development, and our experience in building and maintaining relationships.

New future in Russia

Relationships have been vital in securing a new future for BP in Russia as a 19.75% shareholder in Rosneft. Rosneft is implementing its strategy for growth across a promising portfolio and paid us a dividend of $456 million in 2013. We look forward to exploring opportunities

[a] See footnote a on page 25.

[b] Excludes acquisitions and Rosneft transaction.

[c] See page 247 for further information.

[d] See footnote c on page 56.

[e] See footnote b on page 56.

for BP to work with Rosneft in the years ahead.

Making our case in the US

BP has continued to meet its commitment to environmental and economic restoration in the Gulf of Mexico. We have also been swift to counter illegitimate claims and to argue for a fair resolution to compensation matters. By the end of the year the total cumulative cost to the company had reached $42.7 billion, the scale of that amount underlining once again that BP is living up to its responsibilities in the region and to the US as a whole. The US remains vitally important to today s BP, with around 20,000 employees across the country and we estimate that our economic activity supports a further 240,000 additional jobs. Nearly 40% of our shares are held in the US, and we invest more there than in any other country.

Looking ahead

We are a smaller but stronger company, having divested $38 billion of assets over three years. In October we announced that we would divest around a further $10 billion of assets before the end of 2015 a decision that reflects our commitment to balancing reinvestment with rewards for our shareholders. We expect to use the proceeds predominantly for distributions to shareholders, with a bias to share buybacks.

Our unrelenting focus on capital discipline and systematic operating is increasing the free cash flow[d] we have available. We are on track to meet our goal of generating more than $30 billion of operating cash flow in 2014, an increase of more than 50% on 2011.[e]

I m looking forward to 2014 with great confidence. I think you will see a re-energized and refocused BP a company that is set to become stronger and safer in every way, as we fulfil our mission of delivering energy to customers and value to shareholders.

Bob Dudley

Group Chief Executive

6 March 2014

Table of Contents

Our market outlook

We believe that a diverse mix of fuels and technologies will be essential to meet the growing demand for energy and the challenges facing our industry.

Our third PTA plant in Zhuhai, China, is planned to begin production in late 2014. It is expected to bring total capacity at the site to more than 2.7 million tonnes per year.

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Thunder Horse in the Gulf of Mexico is one of the largest integrated offshore drilling and production platforms in the world.

Population and economic growth are the main drivers of global energy demand. The world s population is projected to increase by 1.7 billion from 2012 to 2035, with real income likely to more than double over the same period.

Therefore, the overall trend is likely to be one of increased energy demand, even with energy and climate policies and a shift towards less energy-intense activities in fast-growing economies. We expect demand for energy to increase by as much as 41% between 2012 and 2035.

Challenges and opportunities

We seek energy sources that have the following attributes:

Affordability meeting growing demand for secure and sustainable energy presents an affordability challenge. Fossil fuels will become increasingly difficult to access and many lower-carbon resources will

A diverse mix

We believe a diverse mix of fuels and technologies can enhance national and global energy security while supporting the transition to a lower-carbon economy. These are reasons why BP s portfolio includes oil sands, shale gas, deepwater oil and gas, and biofuels.

Oil and natural gas

Oil and natural gas are likely to play a significant part in meeting demand for several decades.

We believe these energy sources will represent about 54% of total energy consumption in 2035. Even under the International Energy Agency s most ambitious climate policy scenario (the 450 scenario), oil and gas would still make up 47% of the energy mix in 2035.[a] 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.

remain costly to produce at scale.

Security each country knowing where its supplies will come from. More than 60% of the world s known reserves of natural gas are in just five countries and at least 80% of global oil reserves are located in nine countries, most of which are distant from the hubs of energy consumption. This represents a security challenge in its own right.

Sustainability avoiding an unacceptable environmental and social impact that ultimately negates the economic benefits. While energy is available to meet growing demand, action is needed to limit carbon dioxide (CO_2) and other greenhouse gases emitted through fossil fuel use.

We expect oil to remain the dominant source for transport fuels, accounting for as much as 87% of demand in 2035.

Natural gas, in particular, is likely to play an increasingly strategic role. Shale gas is expected to contribute 47% of the growth in global natural gas supplies between 2012 and 2035. The shale gas revolution has already had a significant impact on gas prices and demand in the US and may encourage similar developments elsewhere although the scale and speed of the roll out of shale gas technology will vary between countries. When used in place of coal for power, natural gas can reduce CO_2 emissions by half.

[a] From *World Energy Outlook 2013*. © OECD/International Energy Agency 2013, page 573.

2013 pricing

See Upstream on page 26 and

Downstream on page 32.

BP Energy Outlook contains our projections of future energy trends and factors that could affect them, based on our views of likely economic and population growth and developments in policy and technology. Available in PDF, Excel and video format.

See *bp.com/energyoutlook*.

Energy consumption by region

(billion tonnes of oil equivalent)

Source: *BP Energy Outlook 2035*.

Energy consumption by fuel

(billion tonnes of oil equivalent)

* Includes biofuels.

Source: *BP Energy Outlook 2035*.

New sources of hydrocarbons are more difficult to reach, extract and process. BP and others in our industry are working to improve techniques for maximizing recovery from existing and currently inaccessible or undeveloped fields. In many cases, the extraction of these resources might be more energy intensive, which means operating costs and greenhouse gas emissions from operations may also increase.

Renewable energy

Renewables will play an increasingly important role in addressing the challenges of energy security and climate change over the long term. Renewables are already the fastest-growing energy source, but they are starting from a low base.

By 2035, we estimate renewable energy, excluding large-scale hydro electricity, is likely to meet around 7% of total global energy demand.

Energy efficiency and innovation

Greater efficiency addresses several aspects of the energy challenge. It helps with affordability because less energy is needed. It helps with security because it reduces dependence on imports. And it helps with sustainability because it reduces emissions.

of energy resources, mutual benefits for resource owners and development partners, and 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 a 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. A global carbon price should be the long-term goal, but regional and national approaches are a good first step, provided temporary financial relief is given to sectors that are exposed to international competition.

Beyond 2035

We expect that growing population and per capita incomes will continue to drive growing demand for energy. These dynamics will be

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 technologies and combustion engines that use biofuels could offer the most cost-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. This includes secure access for exploration and development

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.

Strategy

Find out how BP can help meet energy

demand for years to come on

page 13.

Air BP is one of the world s largest aviation fuels suppliers, marketing aviation fuels and specialist products in more than 45 countries. It sells over seven billion gallons of fuel per year.

Table of Contents

Our business model

We aim to create shareholder value across the

hydrocarbon value chain.

Toledo refinery in Ohio has been in constant operation since 1919. The facility has the capacity to process up to 160,000 barrels of crude per day.

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The redevelopment project at Valhall was one of
BP s most complex field expansion developments and gives the field a further
40-year design life.

A rising global population and increasing levels of prosperity are set to create growing demand for energy for years to come. We can help to meet that demand by producing oil and gas safely and reliably.

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. We aim to create value for our investors and benefits for the communities and societies in which we operate, with the responsible supply of energy playing a vital role in economic development.

Every stage of the hydrocarbon value chain offers 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. In renewable energy our focus is on integrating biofuels into the hydrocarbon value chain, and on wind operations in the US.

Our approach spans everything from exploration to marketing. Integration across the group allows us to share functional excellence more efficiently across areas such as safety and operational risk, environmental and social practices, procurement, technology and treasury management.

A relentless focus on safety remains 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.

Our businesses

For more information on our upstream,

downstream and alternative energy

businesses, see pages 25, 31 and 37

respectively.

Our business model

Finding oil g and gas	Developing and g extracting	Transporting g and trading	Manufacturing and marketing
First, we acquire the rights to explore for oil and gas. Through our exploration activities we are able to renew our portfolio, discover new resources and replenish our development options.	When we find hydrocarbon resources, we create value by seeking to progress them into proved reserves or by divesting if they do not fit with our strategy. If we believe developing and producing the reserves will be advantageous for BP, we produce the oil and gas, then sell it to the market or distribute it to our downstream facilities.	We move oil and gas through pipelines and by ship, truck and train. Using our trading and supply skills and knowledge, we buy and sell at each stage in the value chain. Our presence across major trading hubs gives us a good understanding of regional and international markets and allows us to create value through entrepreneurial trading.	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 illustrated business model see page 2.

Table of Contents

Our strategy

Our goal is to be a focused oil and gas company that

delivers value over volume.

We are pursuing our strategy by setting clear priorities, actively managing a quality portfolio and employing our distinctive capabilities. Our financial objective is to create shareholder value by generating sustainable free cash flow (operating cash flow less net investment). This disciplined approach enables us to invest for the future while aiming to increase distributions to our investors.

Clear priorities

First, we aim to run safe, reliable and compliant operations leading to better operational efficiency and safety performance. We also aim to achieve competitive project execution, which is about delivering projects efficiently so they are on time and on budget. And we aim to make disciplined financial choices, so we can achieve continued growth in operating cash from our underlying businesses and disciplined allocation of capital.

Quality portfolio

Our portfolio of projects and operations is focused where we can generate the most value, and not necessarily the most volume, through our production.

Distinctive capabilities

Our ability to deliver against our priorities and build the right portfolio depends on our distinctive capabilities. We apply advanced technology across the hydrocarbon value chain, from finding resources to developing energy-efficient and high-performance products for customers. We rely on our strong relationships with governments, partners, civil society and others to enable our operations in around 80 countries across the globe. And, the proven expertise of our employees comes to the fore in a wide range of disciplines.

Our strategy in action

See page 14 for more information

on how we are going to measure our

[a] See footnote a on page 56.

[b] Equivalent to net cash used in investing activities.

[c] See footnote c on page 56.

[d] See footnote h on page 24.

[e] Excludes acquisitions and asset exchanges.

[f] Unit cash margin is net cash provided by operating activities

by the relevant projects in our Upstream segment, divided

by the total number of barrels of oil equivalent produced

for the relevant projects.

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

[h] See footnote b on page 56.

[i] See footnote d on page 56.

We undertake active portfolio management to concentrate on areas where we can play to our strengths. This means we continue to grow our exploration position, reloading our upstream pipeline. We focus on high-value upstream assets in deepwater, giant fields and selected gas value chains. And, with our downstream businesses, we plan to leverage our newly upgraded assets, customer relationships and technology to grow free cash flow.

progress.

10-point plan 2011-2014

In 2011 we laid out a 10-point plan designed to stabilize the company and restore trust and value in response to the tragic Deepwater Horizon accident. Our priority was to make BP a safer, more risk-aware business. The plan included a series of milestones by which our progress could be tracked, from 2012 through to 2014. Information on our progress during 2013 can be found in Group performance on page 22.

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

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[f] around double the 2011 average by 2014.[g]

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

management processes.

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

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[i] in the lower half of the 10-20% range over time.

Table of Contents

Our strategy in action

Table of Contents

We prioritize the safety and reliability of our operations to protect the welfare of our workforce and the environment. This also helps preserve value and secure our right to operate around the world.	Recordable injury frequency, loss of primary containment, greenhouse gas emissions, tier 1 process safety events.	**A commitment to safe operations** Toledo refinery sets a safety record. See page 42.	**31** fewer reported losses of primary containment than 2012.
We rigorously screen our investments and we work to keep our annual capital expenditure within a set range. Ongoing management of our portfolio helps ensure focus on more value-driven propositions. We balance funds between shareholder distributions and investment for the future.	Operating cash flow, gearing[a], total shareholder return, replacement cost profit (loss) per ordinary share.	**Maximizing value at Mad Dog** Changing plans to make the best financial choices. See page 29.	**$21.1bn** operating cash flow.
We seek efficient ways to deliver projects on time and on budget, from planning through to day-to-day operations. Our wide-ranging project experience makes us a valued partner and enhances our ability to compete.	Major project delivery.	**Increasing oil production in Azerbaijan** Local construction of BP s heaviest platform in the Caspian Sea. See page 48.	**4** major project start-ups in Upstream and Downstream.
We target basins and prospects with the greatest potential to create value, using our leading subsurface capabilities. This allows us to build a strong pipeline of future growth opportunities.	Reserves replacement ratio.[b]	**Discovering gas in India** Two significant discoveries with Reliance Industries.	**129%** reserves replacement ratio.

See page 30.

We are strengthening our portfolio of high return and longer life assets across deep water, giant fields and gas value chains to provide BP with momentum for decades to come.	Production.[c]	**Preparing for Shah Deniz Stage 2** Largest gas sales contracts in Azerbaijan s history.	**3.2** million barrels of oil equivalent per day.

See page 27.

We benefit from our high-performing fuels, lubricants, petrochemicals and biofuels businesses. Through premium products, powerful brands and supply and trading, Downstream provides strong cash generation for the group.	Refining availability.	**Creating our North American advantaged refinery** Modernization project improves utilization and margin capture at Whiting.	**95.3%** refining availability.

See page 33.

Creating shareholder value by generating

sustainable free cash flow

Advanced technology
We develop and deploy technologies we expect to make the greatest impact on our businesses from enhancing the safety and reliability of our operations to creating competitive advantage in energy discovery,

Strong relationships
We form enduring partnerships in the countries in which we operate, building strong relationships with governments, customers, partners such as Rosneft, suppliers and communities to create mutual

Proven expertise
We attract and develop the talented people required to drive our business forward.

They apply their diverse skills and expertise to deliver complex projects across recovery, efficiency and products.

advantage.
Co-operation helps unlock resources found in
challenging locations and transforms them into
products for our customers.

all areas
of our business.

Table of Contents

Our distinctive capabilities

We use technology to find and produce more hydrocarbons, improve our processes for converting raw materials and develop lower-carbon products.

The development of technology from research and development through to wide-scale deployment can take several years. For example, to reach the next generation of deepwater oil reserves, where rock pressures can reach 20,000 pounds per square inch, we are developing new subsea technologies through our *Project 20K*.

Technology programmes in our upstream business include advanced seismic imaging to help us find more oil and gas and enhanced oil recovery to get more from existing fields. New techniques are making recovery of unconventional oil and gas, like shale, economically viable.

See *bp.com/technology*.

We focus our downstream technology programmes on the safety, integrity and performance of our refineries and petrochemical plants and on creating high quality, energy efficient, cleaner fuels, lubricants and petrochemicals.

BP employs more than 2,000 scientists and technologists.

Our long-term research programmes with universities and research institutions around the world are exploring areas from reservoir fluid flow to energy biosciences. We have a strategic approach to university relationships across our portfolio for the purposes of research, recruitment, policy insights and education.

In 2013 we invested $707 million in research and development (2012 $674 million). See Financial statements Note 8.

Seismic imaging

We use our imaging expertise to increase the productivity and quality of the data we capture on land and offshore. With 80% of future offshore oil and gas reserves thought to be

Enhanced oil recovery (EOR)

Our *LoSal* EOR technology can help develop previously unexploited resources from existing oil fields. *LoSal* uses water with a low salt content to release more molecules of

The Pangbourne technology centre is home to chemists and liquid engineers dedicated to providing products and services for *Castrol* s customers.

under salt canopies up to 7 kilometres high, our new supercomputer in Houston helps to reduce the completion times for imaging jobs from several months to a matter of days.

oil from the sandstone rock where they are held.

Production optimization

Our *Field of the Future* technologies provide real-time information to help manage operational risk, improve plant equipment reliability and optimize production. We use these technologies to monitor more than 600 wells.

Shipping efficiency

Our virtual arrival system can reduce fuel consumption and emissions by allowing vessels, ports and other parties to work together and agree an optimum arrival time for each vessel.

Our employees enable BP to deliver our strategy and meet our commitments to investors, partners and the wider world.

Our people are talented in a wide range of disciplines, from geoscience, mechanical engineering and research technology to government affairs, trading, marketing, legal and others. And our approach to professional development programmes and training helps build individual capabilities, reducing a potential skills gap. This is vital in a world where oil and gas companies face an increasing challenge to find and retain skilled and experienced people.

We aim to achieve a balance between building internal expertise and recruiting external professionals and graduates. We have a strong, experienced leadership team and a pipeline of talent for the future.

Table of Contents

Improved conversion

Our *Veba Combi-Cracking* technology converts a wide variety of raw materials, ranging from crude oil residue to mixtures of coal and oil, into fuels. Using this technology we can convert 95% or more of our hydrocarbon resources to marketable products.

Corrosion prevention

Wireless Permasense® systems, developed in collaboration with Imperial College, London, are used across all our refineries to monitor the integrity of critical oil and gas assets.

Fuels and lubricants

We focus on providing energy-efficient and high-performance products to customers. *Castrol EDGE,* which is underpinned by our proprietary *Fluid Strength Technology,* reduces contact between engine surfaces to improve performance and reduce wear from friction.

Petrochemicals

Our *SaaBre* technology converts synthesis gas (carbon monoxide and hydrogen derived from hydrocarbons) into acetic acid. The process avoids the need to purify carbon monoxide or purchase methanol, reducing manufacturing costs and environmental impacts.

Biofuels

Conversion technology allows us to produce cellulosic ethanol using alternative raw materials such as agricultural waste and fast-growing energy grasses. At our biofuels technology centre in San Diego around 120 scientists are researching and advancing new biofuels technologies.

Our relationships are crucial to the success of our business. We work closely with governments, national oil companies and other resource holders. By acting responsibly and meeting our obligations we build long-lasting relationships.

From experience we know that trust can be lost, so we place enormous importance on meeting people s

contractors. Our activity creates value that benefits governments, customers, local communities and other partners.

Internally we put together collaborative teams of people with the skills and experience needed to address complex issues, work effectively with our partners and help create shared value.

expectations. We work in partnership on big and complex projects with everyone from other oil companies through to suppliers and

Table of Contents

Our key performance indicators

We assess the group s performance according to a wide range of measures and indicators. Our key performance indicators (KPIs) help the board and executive management measure performance against our strategic priorities and 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

This year, we introduced two new KPIs: tier 1 process safety events and major project delivery. These demonstrate two of our strategic objectives and are used as measures for executive remuneration.

We have removed the number of oil spills as a group KPI as this is reflected within the loss of primary containment and tier 1 process safety events KPIs. We continue to report on oil spills, see Safety on page 41.

Replacement cost profit (loss) per ordinary share (cents)

Replacement cost profit (loss) is a useful measure for investors because it is a profitability measure BP management use to assess performance and allocate resources.

It reflects the replacement cost of supplies and is calculated by removing inventory holding gains and losses and their associated tax effect from profit. This is a non-GAAP measure for the group. The IFRS equivalent can be found on page 236.

2013 performance The increase in replacement cost profit per ordinary share for the year compared with 2012 reflected the gain on disposal of our interest in TNK-BP.

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.

2013 performance Higher operating cash flow in 2013 reflected a lower cash outflow relating to the Gulf of Mexico oil spill, partly offset by higher cash outflows as a result of working capital build.

Gearing (net debt ratio) (%)

Our gearing (net debt ratio) shows investors how significant net debt is relative to equity from shareholders in funding BP s operations.

We aim to keep our gearing within the 10-20% range to give us the flexibility to deal with an uncertain environment.

Gearing is calculated by dividing net debt by total equity plus net debt. Net debt is equal to gross finance debt, plus associated derivative financial instruments, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. See Financial statements Note 28 for the nearest equivalent measure on an IFRS basis and for further information.

2013 performance
Gearing at the end of 2013 was 16.2%, down 2.5% on 2012 and within our target band of 10-20%.

Remuneration

To help align the focus of our board and executive management with the interests of our shareholders, certain measures are reflected in the variable elements of executive remuneration.

Overall annual bonuses, deferred bonuses and performance shares are all based on performance against measures and targets linked directly to strategy and KPIs. For details of our remuneration policy see page 96.

KPIs used to measure progress against our strategy.

KPIs used to determine 2013 and 2014 remuneration.

Refining availability (%)

Refining availability represents Solomon Associates operational availability. The measure shows the percentage of the year that a unit is available for processing after deducting the time spent on turnaround activity and all mechanical, process and regulatory maintenance downtime.

Refining availability is an important indicator of the operational performance of our Downstream businesses.

2013 performance
Refining availability increased by 0.5% from 2012 to 95.3% reflecting strong operations around our global refining portfolio.

Reported recordable injury frequency[a]

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

The measure gives an indication of the personal safety of our workforce.

2013 performance Our workforce RIF, which includes employees and contractors combined, was 0.31, compared with 0.35 in 2012 and 0.36 in 2011. These successive reductions are encouraging and we continue pursuing improvement in personal safety.

Loss of primary containment[a]

Loss of primary containment (LOPC) is the number of unplanned or uncontrolled releases of oil, gas or other hazardous materials from a tank, vessel, pipe, railcar or other equipment used for containment or transfer.

By tracking these losses we can monitor the safety and efficiency of our operations as well as our progress in making improvements.

2013 performance Our reported LOPC shows 31 fewer reported incidents in 2013 than in 2012, with divestments accounting for a significant part of the reduction. We remain committed to using our operating management system to further improve our operations.

Table of Contents

Total shareholder return (%)

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

We are committed to maintaining a progressive and sustainable dividend policy.

2013 performance TSR grew as a result of increases in both the BP share price and in the dividend, with the improvement for ordinary shares slightly offset by exchange rate effects.

Reserves replacement ratio (%)

Proved reserves replacement ratio is the extent to which the year s production has been replaced by proved reserves added to our reserve base.

The ratio is expressed in oil-equivalent terms and includes changes resulting from discoveries, improved recovery and extensions and revisions to previous estimates, but excludes changes resulting from acquisitions and disposals. The ratio reflects both subsidiaries and equity-accounted entities.

The measure helps to demonstrate our success in accessing, exploring and extracting resources.

2013 performance The increase in our reserves replacement ratio included the impact of final investment decisions on two significant upstream projects in Oman and

Major project delivery

Major projects are defined as large-scale projects with a high degree of complexity and a BP net investment of at least $250 million.

We monitor the progress of our major projects to gauge whether we are delivering our core pipeline of activity. Projects take many years to complete, requiring differing amounts of resource, so a smooth or increasing trend should not be anticipated.

2013 performance In total we delivered four major projects. Three started up in Upstream Atlantis North expansion Phase 1 in the Gulf of Mexico; Angola LNG; and North Rankin Phase 2 in Australia, and one in Downstream the Whiting refinery modernization project.

Production (mboe/d)

We report the volume of crude oil, condensate, natural gas liquids (NGLs) and natural gas produced by 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.

2013 performance BP s total reported production including our Upstream segment, and our share of TNK-BP (from 1 January to 20 March) and Rosneft (from 21 March to 31 December), was 3% lower than in 2012. This was mainly due to the effect of divestments in Upstream.

Azerbaijan.

Tier 1 process safety events[a]

We report tier 1 process safety events (PSE), which are the losses of primary containment of greatest consequence causing harm to a member of the workforce, costly damage to equipment or exceeding defined quantities.

2013 performance Our reduction in reported tier 1 PSEs is supported by our efforts to drive improvement in process safety. Divestments also account for part of the reduction. We are aware there is always more to do to improve.

[a] 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.

Greenhouse gas emissions

(million tonnes of CO_2 equivalent)

We report greenhouse gas (GHG) emissions material to our business on a carbon dioxide-equivalent basis. This includes CO_2 and methane for direct emissions.[b] Our GHG reporting encompasses all BP s consolidated entities as well as our share of equity-accounted entities other than BP s share of TNK-BP and Rosneft. Rosneft s emissions data can be found on its website.

2013 performance Our total greenhouse gas emissions decreased by 18%, primarily due to the divestment of our Texas City and Carson refineries.

[b] For indirect emissions data see page 45.

Group priorities engagement[c] (%)

We track how engaged our employees are with our strategic priorities for building long-term value. The measure is derived from answers to 12 questions about BP as a company and how it is managed in terms of leadership and standards.

2013 performance We saw continued improvement in 2013, and there was an increase in understanding of our operating management system, an area of focus identified the previous year. While the survey showed an increase in employee confidence in BP s leadership, work is needed to further strengthen this.

[c] Relates to BP employees.

Diversity and inclusion[c] [d] (%)

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

This means we can track progress in building a diverse and well-balanced leadership team, helping to create a sustainable pipeline of diverse talent for the future.

2013 performance We have increased the percentage of female leaders again this year and have extended our focus on diversity and inclusion beyond the board and group leaders to include other levels of management.

[d] Minor amendments have been made to 2012.

Table of Contents

Our approach to executive directors remuneration

Remuneration is directly linked to strategy and performance, with particular emphasis on matching rewards to results over the long term.

A simple approach

Total remuneration is determined by a relatively simple approach to attract and retain high calibre executives. The largest components are share based and vest over a number of years further aligning executives interests with those of our shareholders.

Underpinned by six key principles

The remuneration policy for executive directors and the decisions of the remuneration committee of the board are guided by six key principles:

1 Linked to strategy

A substantial portion of executive remuneration is linked to success in implementing the company s strategy.

Strategic priorities and group key performance indicators (KPIs) provide key metrics for the performance shares and deferred bonus, and are focused through the annual plan to provide the measures for annual bonus.

2 Performance related

The major part of total remuneration varies with performance, with the largest elements share based, further aligning interests with shareholders.

High pay requires high performance. Achieving the maximum pay requires sustained high performance over several years.

Table of Contents

3 Long-term based

The structure of pay is designed to reflect the long-term nature of BP s business and the significance of safety and environmental risks.

The largest components of total remuneration are share based and vest over the longest period. The deferred bonus plan requires sustained safety and environmental performance

over three years. The matched shares that vest under the plan have an additional three-year retention period, resulting in a six-year time frame. Similarly, performance shares have a six-year time frame a three-year performance period followed by an additional three-year retention period for those shares that vest.

4 Informed judgement

There are quantitative and qualitative assessments of performance with the remuneration committee making informed judgements within a framework approved by shareholders.

The committee has a preference for quantifiable targets that can be factually measured and objectively assessed according to well understood principles and definitions. It seeks the views of other relevant committees when arriving at conclusions. It is not constrained when conditions change requiring different perspectives or when unanticipated events, both good and bad, occur.

5 Shareholder engagement

The remuneration committee actively seeks to understand shareholder preferences and be transparent in explaining its policy and practice.

During 2013 the remuneration committee chairman met personally with shareholders representing nearly 15% of total outstanding shares. A number of adjustments to policy were made in response to the feedback received (see page 82).

94%

of votes cast were in favour of the 2012 Directors remuneration report.

6 Fair treatment

Total overall pay takes account of both the external market and company conditions to achieve a balanced, fair outcome.

The committee attempts to balance sometimes conflicting perspectives to arrive at total pay results that not only reflect performance relative to strategy, but also are deemed fair by external stakeholders and employees, as well as the executive team.

Table of Contents

Group performance

Our progress in 2013 has set us up well to deliver our

10-point plan and forms the foundations for delivering

value in the long term.

~

In May we completed the successful commissioning of a state-of-the-art diesel hydrotreater and hydrogen plant at the Cherry Point refinery in Washington state.

{

The Mad Dog field in the Gulf of Mexico was discovered in 1998 and is one of BP s largest discoveries in the Gulf of Mexico to date.

We continued to operate within a disciplined financial framework in 2013 with organic capital expenditure[a] of $24.6 billion (within the expected $24-$25 billion range). Upstream BP-operated plant efficiency[b] of 88% and strong refining availability of 95.3% in Downstream demonstrated our progress in operational efficiency. We completed the transactions to increase our shareholding in Rosneft to 19.75%. And, we are continuing to meet our commitments in the Gulf of Mexico, while making our case in court.

2013-2014 milestones set out in our 10-point plan

Drilling up to 25 wells per year.

g We completed 17 exploration wells and made seven potentially commercial discoveries in 2013. It was our most successful year for exploration drilling in almost a decade.

A further nine major upstream project start-ups.

g Three major projects were started up in 2013 and another three in January and February 2014. We expect a further four major upstream projects to start up in 2014.

Unit operating cash margins[c] from new upstream projects in 2014 are expected to be double the 2011 average.[d]

g We continued to bring on major projects in key regions such as Angola and the Gulf of Mexico.

Segment performance

For Upstream and Downstream performance see pages 25 and 31 respectively.

Bringing onstream the major upgrade to the Whiting refinery in the second half of 2013.

- We completed the commissioning of all major units for the refinery upgrade, transforming it into one of our advantaged downstream assets in our portfolio.

Completing our $38-billion divestment programme by the end of 2013.

- We completed our $38-billion divestment programme in 2012 effectively a year early. In October 2013, we announced our plan to divest a further $10 billion before the end of 2015.

We have a high-value, focused portfolio that plays to our strengths.

- Our divestments have removed complexity, strengthened the balance sheet and left us with a more distinctive set of assets that play to our strengths deep water, gas value chains, giant fields and high-quality downstream businesses.

Increasing overall operating cash flow[e] by 50% in 2014 compared with 2011.[f]

- We are on track to meet our goal of generating more than $30 billion of operating cash flow in 2014.

We expect to use around half of the extra cash for increased investment and around half for other purposes, including increased distributions to shareholders.

- As at 31 December 2013 we had bought back 753 million shares for a total amount of $5.5 billion, including fees and stamp duty, since 22 March 2013. The dividend paid in 2013 was 36.5 cents per share, up 30% compared with the dividend of 28 cents per share paid in 2011.

[a] Organic capital expenditure excludes acquisitions, asset exchanges, and other inorganic capital expenditure.

[b] See footnote a on page 25.

[c] See footnote f on page 13.

[d] See footnote g on page 13.

[e] See footnote a on page 56.

[f] See footnote b on page 56.

Table of Contents

Group performance and outlook

Financial performance

			$ million
	2013	2012	2011
Profit before interest and taxation	**31,769**	19,769	39,815
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(1,548)**	(1,638)	(1,587)
Taxation	**(6,463)**	(6,880)	(12,619)
Non-controlling interests	**(307)**	(234)	(397)
Profit for the year[a]	**23,451**	11,017	25,212
Inventory holding (gains) losses, net of tax[b]	**230**	411	(1,800)
Replacement cost profit[c]	**23,681**	11,428	23,412
Net charge (credit) for non-operating items[d], net of tax	**(10,533)**	5,298	(2,195)
Net (favourable) unfavourable impact of fair value accounting effects[d], net of tax	**280**	345	(47)
Underlying replacement cost profit[c]	**13,428**	17,071	21,170
Capital expenditure and acquisitions	**36,612**	25,204	31,959

Profit for the year ended 31 December 2013 was $23,451 million. After adjusting for $230 million in respect of inventory holding losses and their associated tax effect, replacement cost (RC) profit was $23,681 million. After further adjusting for a net credit of $10,533 million for non-operating items and unfavourable fair value accounting effects (relative to management s measure of performance) of $280 million, both net of tax, underlying RC profit was $13,428 million.

Non-operating items in 2013, on a pre-tax basis, were mainly relating to the $12.5-billion gain on disposal of TNK-BP partially offset by an $845-million write-off attributable to block BM-CAL-13 offshore Brazil as a result of the Pitanga exploration well not encountering commercial quantities of oil or

gas, impairment charges and further charges associated with the Gulf of Mexico oil spill. More information on non-operating items, and fair value accounting effects, can be found on page 237. See Gulf of Mexico oil spill on page 38 and Financial statements Note 2 for further information on the impact of the Gulf of Mexico oil spill on BP s financial results.

For the year ended 31 December 2012, profit was $11,017 million, RC profit was $11,428 million and underlying RC profit was $17,071 million. There was a net post-tax charge of $5,298 million for non-operating items, which included a $5.0-billion pre-tax charge relating to the Gulf of Mexico oil spill.

Compared with 2012, underlying RC profit in 2013 was impacted by the absence of equity-accounted earnings from TNK-BP and lower earnings from both Downstream and Upstream, partially offset by the equity-accounted earnings from Rosneft from 21 March 2013 (when sale and purchase agreements with Rosneft and Rosneftegaz completed).

For the year ended 31 December 2011, profit was $25,212 million, RC profit was $23,412 million and underlying RC profit was $21,170 million. There was a net post-tax credit for non-operating items of $2,195 million, which included a $3.8-billion pre-tax credit relating to the Gulf of Mexico oil spill.

Compared with 2011, underlying RC profit in 2012 was impacted by significantly lower earnings from Upstream and the absence of equity-accounted earnings from TNK-BP from 22 October 2012 (when our investment was reclassified as an asset held for sale, as required under IFRS), partially offset by improved earnings from Downstream.

See Upstream on page 25, Downstream on page 31, Rosneft on page 35 and Other businesses and corporate on page 37 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.

Net finance expense relating to pensions and other post-retirement benefits in 2013 was $480 million (2012 $566 million, 2011 $400 million).

In 2013, we adopted the revised version of IAS 19 Employee Benefits , under which we apply the same expected rate of return on plan assets as we used to discount our pension liabilities. Financial information for prior periods has been restated see Financial statements Note 1 for further information.

Taxation

The charge for income taxes in 2013 was $6,463 million (2012 $6,880 million, 2011 $12,619 million). The effective tax rate was 21% in 2013 (2012 38%, 2011 33%). The decrease in the effective tax rate in 2013 compared with 2012 primarily relates to the gain on disposal of TNK-BP in 2013 for which there was no corresponding tax charge. 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 relating to the Gulf of Mexico oil spill, which is not tax deductible.

[a] Profit attributable to BP shareholders.

[b] 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 segment is shown in Financial statements Note 7 and further information on inventory holding gains and losses is provided on page 269.

[c] 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 and underlying RC profit or loss, see Certain definitions on page 269.

[d] Non-operating items are charges and credits arising in consolidated entities and in TNK-BP and Rosneft that are included in the financial statements and that BP discloses separately because it considers such disclosures to be meaningful and relevant to investors. The main categories of non-operating items included here are: impairments; gains and losses on sale of businesses and fixed assets; environmental remediation costs; restructuring, integration and rationalization costs; and changes in the fair value of embedded derivatives. Fair value accounting effects are non-GAAP adjustments to our IFRS profit relating to certain physical inventories, pipelines and storage capacity. Management uses a fair-value basis to value these items which, under IFRS, are accounted for on an accruals basis with the exception of trading inventories, which are valued using spot prices. The adjustments have the effect of aligning the valuation basis of the physical positions with that of the derivative instruments, which are required to be fair valued under IFRS, in order to provide a more representative view of the ultimate economic value. See page 238 and Certain definitions on page 269 for more information.

Operating cash flow

Operating cash flow is net cash provided by operating activities, as presented in the group cash flow statement on page 125. Operating cash flow in 2013 was $21.1 billion (2012 $20.5 billion, 2011 $22.2 billion). Excluding the impact of the Gulf of Mexico oil spill, net operating cash flow in 2013 was $21.2 billion (2012 $22.9 billion, 2011 $29.0 billion).

Shareholder distributions

Total dividends paid in 2013 were 36.5 cents per share, up 11% compared with 2012 on a dollar basis and 12% in sterling terms. This equated to a total cash distribution to shareholders of $5.4 billion during the year.

Group reserves and production

	2013	2012	2011
Estimated net proved reserves			
(net of royalties)[a]			
Liquids[b]			million barrels
Subsidiaries	**4,349**	4,672	5,331
Equity-accounted entities[c]	**5,721**	5,378	5,234
	10,070	10,050	10,565
Natural gas			billion cubic feet
Subsidiaries	**34,187**	33,264	36,381
Equity-accounted entities[c]	**11,788**	7,041	5,278
	45,975	40,305	41,659
Total hydrocarbons[d]			million barrels of oil equivalent
Subsidiaries	**10,243**	10,408	11,604
Equity-accounted entities[c]	**7,753**	6,592	6,144
	17,996	17,000	17,748
Production (net of royalties)[e]			
Liquids[f]			thousand barrels per day
Subsidiaries	**879**	896	992
Equity-accounted entities[g]	**1,134**	1,160	1,165
	2,013	2,056	2,157
Natural gas			million cubic feet per day
Subsidiaries	**5,845**	6,193	6,393
Equity-accounted entities[g]	**1,216**	1,200	1,125
	7,060	7,393	7,518
Total hydrocarbons[d]			thousand barrels of oil equivalent per day
Subsidiaries	**1,887**	1,963	2,094
Equity-accounted entities[g]	**1,343**	1,367	1,360
	3,230	3,331	3,454

[a] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[b] Liquids comprise crude oil, condensate, NGLs and bitumen.
[c] Includes BP s share of Rosneft and TNK-BP reserves. See Rosneft on page 36 and Supplementary information on oil and natural gas on page 200 for further information.
[d] Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.
[e] Because of rounding, some totals may not agree exactly with the sum of their component parts.
[f] Liquids comprise crude oil, condensate and NGLs.
[g] Includes BP s share of Rosneft and TNK-BP production. See Rosneft on page 36 and Oil and gas disclosures for the group on page 245 for further information.

Total hydrocarbon proved reserves, on an oil equivalent basis including equity-accounted entities, comprised 17,996mmboe (10,243mmboe for subsidiaries and 7,753mmboe for equity-accounted entities) at 31 December 2013, an increase of 6% (decrease of 2% for subsidiaries and increase of 18% for equity-accounted entities) compared with the 31 December 2012 reserves of 17,000mmboe (10,408mmboe for subsidiaries and 6,592mmboe for equity-accounted entities). Natural gas represented about 44% (58% for subsidiaries and 26% for equity-accounted entities) of these reserves. The change includes a net increase from acquisitions and disposals of 641mmboe (200mmboe net decrease for subsidiaries and 841mmboe net increase for equity-accounted entities). Net divestments in our subsidiaries occurred in the UK, the US, China and Canada. We had sales and purchases, as a consequence of our divestment of TNK-BP and investment in Rosneft.

Our total hydrocarbon production during 2013 averaged 3,230 thousand barrels of oil equivalent per day (mboe/d). This comprised 1,887mboe/d for subsidiaries and 1,343mboe/d for equity-accounted entities, a decrease of 4% (decreases of 2% for liquids and 6% for gas) and a decrease of 2% (decrease of 2% for liquids and increase of 1% for gas) respectively compared with 2012.

More information on reserves and production, see Oil and gas disclosures for the group on page 245.

Critical accounting policies

The accounting policies, judgements, estimates and assumptions which most affect the financial statements are described in Note 1 to the financial statements.

Outlook

This discussion contains forward-looking statements, which by their nature 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. You are urged to read Risk factors on page 51 and Cautionary statement on page 271, 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.

We expect net cash provided by operating activities of between $30-$31 billion in 2014.[h]

We expect capital expenditure, excluding acquisitions and asset exchanges, to be around $24-$25 billion in 2014, and between $24-$26 billion in the years 2015 to 2018.

We will continue to target our net debt ratio in the 10-20% range while uncertainties remain. Net debt is a non-GAAP measure.

Depreciation, depletion and amortization in 2014 is expected to be around $1 billion higher than in 2013.

For 2014, the underlying effective tax rate (ETR) (which excludes non-operating items and fair value accounting effects) is expected to be around 35%, which is the same as the underlying ETR in 2013.

[h] Assumes $100/bbl oil and $5/mmBtu Henry Hub gas. The projection includes BP s estimate of the Rosneft dividend and the impact of payments in respect of federal criminal and securities claims with the US government and SEC where settlements have already been reached, but 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.

Table of Contents

Upstream

In 2013 we continued to actively manage and simplify our portfolio, strengthening our incumbent positions to provide a platform for growing value.

~

Skarv started up in December 2012 and produces up to 160mboe/d. The field development includes around 50 miles of gas export pipeline that allows export to markets in Europe.

Our business model and strategy

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. In 2013 our activities took place in 27 countries.

We deliver our exploration, development and production activities through five global technical and operating functions:

- The **exploration** function is responsible for renewing our resource base through access, exploration and appraisal, while the **reservoir development** function is responsible for the stewardship of our resource portfolio.

- The **global wells organization** and the **global projects organization** are responsible for the safe, reliable and compliant execution of wells (drilling and completions) and major projects, respectively.

- The **global operations organization** is responsible for safe, reliable and compliant operations, including upstream production assets and midstream transportation and processing activities.

The delivery of these activities is optimized and integrated with support from global functions with specialist areas of expertise: technology, finance, procurement and supply chain, human resources and information technology.

Technologies such as seismic imaging, enhanced oil recovery and real-time data support our upstream strategy by helping to gain new access, increasing recovery and reserves and improving production efficiency (see Our distinctive capabilities on page 16).

We actively manage our portfolio and are placing increasing emphasis on accessing, developing and producing from fields able to provide the greatest value (this includes those with the potential to make the highest contribution to our operating cash flow). We sell assets that we believe have more value 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 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.

A simpler, more focused portfolio with strengthened incumbent positions and reduced operating complexity.

Playing to our strengths exploration, deep water, giant fields and gas value chains.

An execution model that drives improvement in efficiency and reliability through both operations and investment.

A bias to oil with selective gas value chains focusing on where we have strong core positions, can play in premium growth markets or bring advantaged technology to bear.

Strong relationships built on mutual advantage, deep knowledge of the basins in which we operate, and technology.

Outlook

We have announced plans to establish a separate BP business to manage our onshore oil and gas assets in the US lower 48, which we expect to be operational in early 2015. Our goal is to build a stronger, more competitive and sustainable business that we expect to be a key component of BP s portfolio in the future.

We expect reported production in 2014 to be lower than 2013, mainly due to the expiration of the Abu Dhabi onshore concession, with an impact of around 140mboe/d, and divestments. After adjusting for the impacts of the concession expiry, divestments and entitlement effects in our production-sharing agreements (PSAs), we expect underlying production to be higher in 2014.

In addition to the Chirag oil, Mars B and Na Kika Phase 3 projects, which started up in January and February, we expect a further four major projects to come onstream in 2014, which will contribute to the group s plan to generate an increase of around 50% in operating cash flow in 2014 compared with 2011.[c]

Capital investment in 2014 is expected to increase, largely reflecting the progression of our major projects.

[a] Plant efficiency is the actual production of a plant facility expressed as a percentage of the total achievable installed production capacity of the asset including the reservoir, well, plant and export systems.
[b] Underlying replacement cost (RC) profit before interest and tax is not a recognized GAAP measure. See footnote c on page 23 for further information. The equivalent measure on an IFRS basis is RC profit before interest and tax.
[c] See footnote b on page 56.

Table of Contents

Our markets

	2013	2012	2011
Average oil marker prices[a]			$ per barrel
Brent	**108.66**	111.67	111.26
West Texas Intermediate	**97.99**	94.13	95.04
Average natural gas marker prices	$ per million British thermal units		
Average Henry Hub gas price[b]	**3.65**	2.79	4.04
			pence per therm
Average UK National Balancing Point gas price[a]	**67.99**	59.74	56.33

[a] All traded days average.
[b] Henry Hub First of Month Index.

Crude oil benchmark prices

Brent remains an integral marker to the production portfolio, from which a significant proportion of production is priced directly or indirectly. Certain regions use other local markers, which are derived using differentials or a lagged impact from the Brent crude oil price.

Crude oil prices, as demonstrated by the industry benchmark of dated Brent, averaged $108.66 per barrel in 2013, compared with an average of $111.67 per barrel in 2012. This represented the third consecutive year with the dated Brent average price above $100 per barrel. Prices weakened in early 2013 amid strong growth of light, sweet oil production in the US, but rebounded later in the year due to a range of supply disruptions and heightened market perceptions of risks to supply.

Brent ($/bbl)

Amid continued high oil prices, global oil consumption increased, rising by roughly 1.2 million barrels per day for the year compared with 2012 (1.3%), in part boosted by cold weather early in the year.[c] The growth in consumption was slightly exceeded by growth in non-OPEC production, which was dominated by continued strong growth in US output. However, OPEC crude oil production fell due to ongoing Iran sanctions and renewed outages in Libya. As a result, OECD commercial oil inventories remained relatively balanced.

Global oil consumption in 2012 grew by roughly 0.9 million barrels per day compared with 2011 (0.9%).[d] OPEC production met most of the growth in consumption, driven by the recovery in Libyan production.

We expect oil price movements in 2014 to continue to be driven by the pace of global economic growth and its resulting implications for oil consumption, by supply growth in North America, and OPEC production decisions. Risks to supply remain a key uncertainty.

[c] From *Oil Market Report 21 January 2014*©, OECD/IEA 2014, page 1.
[d] *BP Statistical Review of World Energy June 2013.*

Natural gas prices

Natural gas prices continued to show wide differentials between regions in 2013, although widening of the differentials stagnated as US gas prices recovered from their 2012 lows. The Henry Hub First of Month Index averaged $3.65 in 2013, an increase of 31% versus 2012.

Henry Hub ($/mmBtu)

The US natural gas market saw a gradual return to balance in 2013, following the dramatic loss of heating demand in 2012 due to unusually warm winter weather, which pushed gas prices down to 10-year lows. A return to more normal weather in 2013 restored heating demand for gas, which meant less pressure on gas to compete with coal for a share of the power generation market, allowing gas prices to recover. US gas supply continued to expand in 2013, reaching yet another record production level, supported in particular by rising liquids-rich (wet) gas production.

In Europe, gas prices at the UK National Balancing Point increased by 14% to an average of 67.99 pence per therm for 2013. Record-low inventory levels, coming out of a prolonged winter, coupled with declining European gas production and continued diversion of LNG to the higher-priced Asian market, caused European spot prices to climb to a five-year high. European demand remained weak, especially in power generation where gas remained uncompetitive against coal.

Global LNG supply expanded in 2013, following a contraction in supply in 2012. However the LNG market remained tight, with continued strong demand in Asia due to economic growth and nuclear power outages, and also in Latin America due to the impact of a drought on hydroelectric production.

In 2012 the strength of shale gas production in the US, combined with an unusually warm winter, led the average Henry Hub First of Month Index to fall by 31% to $2.79/mmBtu. In the UK, National Balancing Point prices averaged 59.74 pence per therm, 6% above prices in 2011.

In 2014 we expect gas markets to continue to be driven by the economy, weather, production, trade developments and continued 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 2014.

Table of Contents

Financial performance

			$ million
	2013	2012	2011
Sales and other operating revenues[e]	**70,374**	72,225	75,754
RC profit before interest and tax	**16,657**	22,491	26,358
Net (favourable) unfavourable impact of non-operating items and fair value accounting effects[f]	**1,608**	(3,055)	(1,141)
Underlying RC profit before interest and tax[g]	**18,265**	19,436	25,217
Capital expenditure and acquisitions	**19,115**	18,520	25,821
BP average realizations[h]			$ per barrel
Crude oil	**105.38**	108.94	107.91
Natural gas liquids	**38.38**	42.75	51.18
Liquids[i]	**99.24**	102.10	101.29
		$ per thousand cubic feet	
Natural gas	**5.35**	4.75	4.69
US natural gas	**3.07**	2.32	3.34
	$ per thousand barrels of oil equivalent		
Total hydrocarbons[j]	**63.58**	61.86	62.31

[e] Includes sales to other segments.

[f] Fair value accounting effects are not a recognized GAAP measure and represent the (favourable) unfavourable impact relative to management s measure of performance (see page 238 for further details).

[g] Underlying RC profit is not a recognized GAAP measure. See footnote c on page 23 for information on underlying RC profit.

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

[i] Liquids comprise crude oil, condensate and natural gas liquids (NGLs).

[j] Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Sales and other operating revenues for 2013 were $70 billion (2012 $72 billion, 2011 $76 billion). The decrease in 2013, compared with 2012, primarily reflected lower volumes due to disposals and lower realizations, partially offset by higher gas marketing and trading revenues. The decrease in 2012, compared with 2011, primarily reflected lower production and persistently low Henry Hub gas prices.

In 2013 replacement cost (RC) profit before interest and tax for the segment was $16.7 billion (2012 $22.5 billion, 2011 $26.4 billion). The 2013 result included a net non-operating charge of $1,364 million, primarily related to an $845-million write-off attributable to block BM-CAL-13 offshore Brazil as a result of the Pitanga exploration well not encountering commercial quantities of oil or gas, and impairment and other charges partly offset by fair value gains on embedded derivatives and disposal gains. In addition, fair value accounting effects had an unfavourable impact of $244 million relative to management s measure of performance. The 2012 result included net non-operating gains of $3,189 million, primarily as a result of gains on disposals being partly offset by impairment charges. In addition, fair value accounting effects had an unfavourable impact of $134 million. The 2011 result included net non-operating gains of $1,130 million, primarily as 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.

After adjusting for non-operating items and fair value accounting effects, underlying RC profit before interest and tax in 2013 was $18.3 billion (2012 $19.4 billion, 2011 $25.2 billion). Compared with 2012, the decrease in 2013 reflected lower production due to divestments, lower liquids realizations and higher costs, including exploration write-offs and higher depreciation, depletion and amortization, partly offset by an increase in underlying volumes, a benefit from stronger gas marketing and trading activities, a one-off benefit to production taxes as a result of fiscal relief allowing immediate deduction of past costs, a one-off benefit, mainly in respect of prior years, resulting from the US Federal Energy Regulatory Commission approval of cost pooling settlement agreements between the owners of the Trans-Alaska Pipeline System (TAPS) and higher gas realizations. Compared with 2011, the 2012 result reflected 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 2013 was $19.1 billion (2012 $18.5 billion, 2011 $25.8 billion).

Provisions for decommissioning decreased from $17.4 billion at the end of 2012 to $17.2 billion at the end of 2013. The decrease reflects primarily a reduction due to the change in discount rate and utilization of provisions largely offset by updated estimates of the cost of future decommissioning and additions. Decommissioning costs are initially capitalized within fixed assets and are subsequently depreciated as part of the asset.

Acquisitions and disposals

In total, disposal transactions generated $1.3 billion in proceeds during 2013, with a corresponding reduction in net proved reserves of 200mmboe, all within our subsidiaries. There were no significant acquisitions in 2013.

Disposals

The major disposal transactions during 2013 were the sale of our interests in the Harding (BP 70%), Maclure (BP 37.04%), Braes (BP 27.7%),

Table of Contents

Major projects portfolio

Braemar (BP 52%) and Devenick (BP 88.7%) fields in the North Sea to TAQA Bratani Ltd for $1,058 million plus future payments which, depending on oil price and production, are currently expected to exceed $180 million after tax; and the sale of our interests in the Yacheng (BP 34.3%) field in China for $308 million, both of which are subject to post-closing adjustments. More information on disposals is provided in Upstream analysis by region on page 239 and Financial statements Note 5.

Exploration

The group explores for oil and natural gas under a wide range of licensing, joint arrangement and other contractual agreements. We may do this alone or, more frequently, with partners. BP acts as operator for many of these ventures.

New access in 2013

We gained access to new potential resources covering more than 43,000km^2 in seven countries (Canada, Brazil, Greenland, Norway, Egypt, the UK and China). In addition, we entered into three farm-out agreements with Kosmos Energy, covering around 25,000km^2 over three blocks offshore Morocco, one of which is still subject to government approval.

During the year we participated in seven potentially commercial discoveries including the following that we announced: two off the east coast of India on blocks KG D6 and CYD5; one in Egypt with the Salamat well in the East Nile Delta; one in the pre-salt play of Angola with the Lontra well in Block 20, operated by Cobalt International Energy, Inc.; one in the Paleogene play in the Gulf of Mexico with the Gila prospect; and one in Brazil on block BM-POT-17 in the Potiguar basin, operated by Petrobras.

Exploration and appraisal costs

Exploration and appraisal costs, excluding lease acquisitions, were $4,811 million (2012 $4,356 million, 2011 $2,413 million). 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 47% of exploration

and appraisal costs were directed towards appraisal activity. We participated in 140 gross (41 net) exploration and appraisal wells in 11 countries.

Exploration expense

Total exploration expense of $3,441 million (2012 $1,475 million, 2011 $1,520 million) included the write-off of expenses related to unsuccessful drilling activities in Brazil ($388 million), the UK North Sea ($262 million), Angola ($232 million), the Gulf of Mexico ($210 million), Jordan ($121 million) and others ($91 million). It also included an $845-million write-off associated with the value ascribed to block BM-CAL-13 offshore Brazil as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011 and a $257-million write-off for costs relating to the Risha concession in Jordan. In addition, exploration expense included an $88-million credit related to a reduction in provisions for the decommissioning of idle infrastructure, which is required by the Bureau of Ocean Energy Management Regulation and Enforcement s Notice of Lessees 2010 G05 issued in October 2010.

Upstream reserves

	2013	2012	2011
Estimated net proved reserves			
(net of royalties)			
Liquids[a]			million barrels
Subsidiaries[b]	**4,349**	4,672	5,331
Equity-accounted entities[c]	**745**	838	929
	5,094	5,510	6,260
Natural gas			billion cubic feet
Subsidiaries[d]	**34,187**	33,264	36,381
Equity-accounted entities[c]	**2,517**	2,549	2,397
	36,704	35,813	38,778
Total hydrocarbons			million barrels of oil equivalent
Subsidiaries	**10,243**	10,408	11,604
Equity-accounted entities[c]	**1,179**	1,277	1,342
	11,422	11,685	12,946

[a] Liquids comprise crude oil, condensate, NGLs and bitumen.
[b] Includes 21 million barrels (14 million barrels at 31 December 2012 and 20 million barrels at 31 December 2011) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC.
[c] BP s share of reserves of equity-accounted entities in the Upstream segment. During 2013, upstream operations in Abu Dhabi, Argentina and Bolivia, as well as some of our operations in Angola and Indonesia, were conducted through equity-accounted entities.
[d] Includes 2,685 billion cubic feet of natural gas (2,890 billion cubic feet at 31 December 2012 and 2,759 billion cubic feet at 31 December 2011) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC.

Reserves booking

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 11,422mmboe (10,243mmboe for subsidiaries and 1,179mmboe for equity-accounted entities) at 31 December 2013, a decrease of 2% (decrease of 2% for subsidiaries and decrease of 8% for equity-accounted entities) compared with the 31 December 2012 reserves of 11,685mmboe (10,408mmboe for subsidiaries and 1,277mmboe for equity-accounted entities).

Proved reserves replacement ratio

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 2013 the proved reserves replacement ratio for the Upstream segment, excluding acquisitions and disposals, was 93% for subsidiaries and equity-accounted entities, 105% for subsidiaries alone and 30% for equity-accounted entities alone. For more information on proved reserves replacement for the group, see page 247.

Developments

The map on page 28 shows our major development areas, which include Alaska, Angola, Australia, Azerbaijan, Canada, Egypt, the deepwater Gulf of Mexico and the UK North Sea.

Three major project start-ups were achieved in 2013: Atlantis North expansion Phase 1 in the Gulf of Mexico; Angola LNG; and North Rankin Phase 2 in Australia.

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

Angola   we had our first LNG cargo in June and at the end of 2013 around 1 million cubic metres of LNG had been produced. The Plutão, Saturno, Vénus and Marte (PSVM) project reached plateau production of 150mb/d and the Cravo, Lirio, Orquidea, Violeta (CLOV) floating production storage and offloading vessel (FPSO) sailed away from Angola Paenal in January 2014 to start the offshore hook-up and commissioning campaign.

Azerbaijan   the Shah Deniz consortium   a seven-member group led by BP   selected the Trans Adriatic Pipeline to deliver gas volumes from the Shah Deniz Stage 2 project to customers in Greece, Italy and southern Europe. In

August, 25-year sales agreements were concluded for over 10bcma of gas, to be produced from the Shah Deniz field as a result of Stage 2. This adds to existing agreements to sell 6bcma in Turkey. The final investment decision on the project was made in December.

North Sea we continued to see high levels of activity, including the ramp-up of major project volumes, a significant level of turnaround activity, progress in the major redevelopment of the west of Shetland Schiehallion and Loyal fields, the installation of the platform jackets on the Clair Ridge project, a major milestone, and the sale of a number of non-strategic assets.

Gulf of Mexico we had 10 rigs operating at the end of the year, the highest number ever. Atlantis North expansion Phase 1 started up in April. Following our strategic divestment programme, we now have a very focused portfolio with growth potential around four operated and three non-operated hubs.

In April the decision was taken not to move forward with the existing development plan for the Mad Dog Phase 2 project in the deepwater Gulf of Mexico, as market conditions and industry cost inflation made the project less attractive than previously modelled. This decision resulted in an impairment of $159 million. BP and its co-owners reviewed alternative development concepts and the current concept being considered is a single production host designed for future flexibility in evaluating how best to capture additional potential resource.

Development expenditure of subsidiaries incurred in 2013, excluding midstream activities, was $13.6 billion (2012 $12.6 billion, 2011 $10.4 billion).

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, Australia, Azerbaijan, Egypt, Trinidad, the UAE, the UK and the US.

Table of Contents

	2013	2012	2011
Production (net of royalties)[a]			
Liquids[b]		thousand barrels per day	
Subsidiaries	**879**	896	992
Equity-accounted entities	**297**	284	294
	1,176	1,179	1,285
Natural gas		million cubic feet per day	
Subsidiaries	**5,845**	6,193	6,393
Equity-accounted entities	**415**	416	415
	6,259	6,609	6,807
Total hydrocarbons[c]	thousand barrels of oil equivalent per day		
Subsidiaries	**1,887**	1,963	2,094
Equity-accounted entities	**369**	355	366
	2,256	2,319	2,460

[a] 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.

[b] Liquids comprise crude oil, condensate and NGLs.

[c] Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Our total hydrocarbon production during 2013 averaged 2,256 thousand barrels of oil equivalent per day (mboe/d). This comprised 1,887mboe/d for subsidiaries and 369mboe/d for equity-accounted entities, a decrease of 4% (decreases of 2% for liquids and 6% for gas) and an increase of 4% (increase of 5% for liquids and no change for gas) respectively compared with 2012. More information on production can be found in Oil and gas disclosures for the group on page 245.

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 3.2% higher compared with 2012. This primarily reflects new major project volumes in Angola, the North Sea and the Gulf of Mexico.

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.

Gas marketing and trading activities

We market and trade natural gas, power and natural gas liquids (NGLs). This provides us with routes into liquid markets for the gas we produce. It also generates margins and fees from selling physical products and derivatives to third parties, together with income from asset optimization and trading. The integrated supply and trading function manages the group s trading activities in natural gas, power and NGLs. This means we have a single interface with the gas trading markets and one consistent set of trading compliance processes, systems and controls.

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 historically volatile. Market conditions have become more challenging in recent years as volatility and geographic basis/seasonal spreads have fallen to very low levels with the emergence of shale gas in the US and generally over-supplied markets in Europe. However, the traded LNG business has benefited from wide price variations between the main gas consuming regions of North America, Europe and Asia. As part of the LNG strategy, during 2013 we entered into a 20-year gas liquefaction tolling contract for 4.4 million tons per annum capacity which is located in Texas, US.

The gas and power marketing and trading function operates primarily from offices in Houston and London and employs around 1,200 people.

The group s risk governance framework seeks to manage and oversee the financial risks associated with this trading activity, which is described in Financial statements Note 19.

In connection with its trading activities, the group uses a range of commodity derivative contracts, storage and transport contracts. The range of contracts that the group enters into is described in Certain definitions commodity trading contracts on page 270.

Analysis by region

See Upstream analysis by region on page 239.

Table of Contents

Downstream

2013 was a year of improved safety performance, operational improvements and delivery of significant milestones to enhance the quality of our portfolio.

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Cherry Point refinery processes around 230,000 barrels of crude oil per day, primarily for transportation fuels.

Our business model and strategy

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 also manufacture and market our products across Australasia, southern Africa and Central and South America.

The segment comprises three businesses:

- **Fuels** fuels value chains (FVCs) including refineries, fuels marketing businesses and global oil supply and trading activities. We sell refined petroleum products including gasoline, diesel, aviation fuel and LPG.

- **Lubricants** manufactures and markets lubricants and related products and services globally, adding value through brand, technology and relationships, such as collaboration with original equipment manufacturing partners.

- **Petrochemicals** manufactures products at locations around the world, using proprietary BP technology. These products are then used by others to make vital consumer products such as paint, plastic bottles and textiles.

We aim to operate all of our businesses as safe and reliable value chains. We participate in multiple stages of each value chain as we believe we can deliver greater returns from integration than from owning a collection of discrete assets. These value chains, combined with our advantaged manufacturing operations, supply and trading capability and expertise in technology, allow us to pursue long-term competitive returns and sustainable growth, serving customers and promoting BP and our brands through high quality products.

We research, develop and deploy a wide range of technologies, processes and techniques, aiming to enhance safety and risk management, increase efficiency and reliability, improve our margins and create new market opportunities.

Our strategy focuses on four priorities executed in a systematic and disciplined way:

- Safety performance.
- High-quality downstream portfolio.
- Competitive returns.
- Material and growing cash flows for the group through exposure to growth opportunities and markets.

This strategy is about winning sustainably in the markets where we choose to participate. We seek to outperform the best competitor in a region and do it safely; investing to strengthen our established positions while maintaining overall capital employed, and still seeking to shift the mix of participation and capital employed from established to growing markets. We do this while operating within a stable financial framework to deliver attractive returns and growth in earnings and cash flow.

The delivery of these activities is optimized and integrated with support from global functions with specialist areas of expertise: technology, finance, procurement and supply chain, human resources, global business services and information technology.

Outlook

- In 2014 we anticipate refining margins will remain under pressure due to high gasoline stocks and new competitor capacity additions, as well as weak demand in many markets.
- We expect the financial impact of refinery turnarounds in 2014 to be lower than in 2013.
- Whiting continues to progressively increase heavy crude processing, and we expect to reach heavy crude processing levels of 280,000 barrels per day during the second quarter 2014.
- We anticipate demand for lubricants in 2014 will be similar to 2013.
- We expect a similarly challenging environment for petrochemicals in 2014, characterized by excess supply.

Capital expenditure is forecast to be slightly lower in 2014 than in 2013, post commissioning of all major units of the Whiting refinery modernization project.

[a] Underlying RC profit before interest and tax is not a recognized GAAP measure. See footnote c on page 23 for further information. The equivalent measure on an IFRS basis is RC profit before interest and tax.

Our markets

Economic growth in 2013 varied widely, with certain economies shrinking and others showing some signs of recovery. OECD oil consumption was up slightly in 2013, rising for the first time since 2010. Demand in non-OECD economies also continued to grow, but at a slower rate than 2012 partly due to reduced GDP growth, for example in India, South East Asia and the Middle East.

In oil markets in 2013, European refineries were impacted by limited economic options to process sour grades, such as Urals, and by the loss of Libyan sweet crude supplies for much of the year. In addition, crude supplies were constrained by the loss of Iranian oil due to US and European trade embargoes and by ongoing decline in European oil production. This was partially offset by Saudi Arabia crude production, which reached a 30-year high.

Non-OPEC oil supply increased by over 1 million barrels per day in 2013, primarily in the US due to increased production of shale oil. North American crudes remained cheaper than waterborne crudes of a similar quality, such as European Brent and Gulf Coast LLS, due to increased production, combined with logistical constraints in transporting inland crude production to the coast. Our refineries, particularly Toledo and Whiting in the US, benefited from a location advantage as they were able to access these discounted crudes. In addition, these refineries benefited from a wider discount of Canadian heavy to West Texas intermediate (WTI) crude in 2013, a factor that will become increasingly important to the BP refining portfolio in 2014 with the commissioning of the Whiting refinery modernization project.

Refining marker margin

We track the margin environment by way of a global refining marker margin (RMM). 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 using a simplified indicator that reflects the margins achieved on gasoline and diesel only. 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. The RMM does not include estimates of fuel costs or other variable costs.

				$ per barrel
	Crude marker	**2013**	2012	2011
Refining marker margin (RMM)				
US North West	Alaska North Slope	**15.2**	18.0	14.1
US Midwest	West Texas Intermediate	**21.7**	27.8	24.7
Northwest Europe	Brent	**12.9**	16.1	11.9
Mediterranean	Azeri Light	**10.5**	12.7	9.0
Australia	Brent	**13.4**	14.8	12.2
BP average RMM		**15.4**	18.2	14.5

In February 2013 BP updated the RMM methodology and regions to reflect the changes to our US portfolio after the refinery divestments and account for trends in regional crude markets since the RMM was established. The effect of this update is that the 2012 and 2011 BP average RMMs were restated from $15.0 per barrel (as originally reported) to $18.2 per barrel and from $11.6 per barrel to $14.5 per barrel, respectively.

Global refining marker margin ($/bbl)

The average RMM for 2013 was $2.8 per barrel lower compared to 2012, with a slightly stronger first half and falling sharply in the second half of the year. However, it was higher than 2011. Margins in 2013 declined primarily due to increased product and gasoline supply, high gasoline inventories, competitor capacity additions and lower seasonal turnarounds.

Financial performance

			$ million
	2013	2012	2011
Sale of crude oil through spot and term contracts	**79,394**	56,383	57,055
Marketing, spot and term sales of refined products	**258,015**	274,666	273,940
Other sales and operating revenues	**13,786**	15,342	13,038
Sales and other operating revenues[a]	**351,195**	346,391	344,033
RC profit before interest and tax[b]			
Fuels	**1,518**	1,403	2,999
Lubricants	**1,274**	1,276	1,350
Petrochemicals	**127**	185	1,121
	2,919	2,864	5,470
Net (favourable) unfavourable impact of non-operating items and fair value accounting effects[c]			
Fuels	**712**	3,609	640
Lubricants	**(2)**	9	(100)
Petrochemicals	**3**	(19)	(1)
	713	3,599	539
Underlying RC profit before interest and tax[b] [d]			
Fuels	**2,230**	5,012	3,639
Lubricants	**1,272**	1,285	1,250
Petrochemicals	**130**	166	1,120
	3,632	6,463	6,009
Capital expenditure and acquisitions	**4,506**	5,249	4,285

[a] Includes sales to other segments.

[b] 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.

[c] Fair value accounting effects are not a recognized GAAP measure and represent the (favourable) unfavourable impact relative to management s measure of performance (see page 238 for further details). For Downstream, these arise solely in the fuels business.

[d] Underlying RC profit is not a recognized GAAP measure. See footnote c on page 23 for information on underlying RC profit.

Sales and other operating revenues in 2013 were $351 billion (2012 $346 billion, 2011 $344 billion). This increase in 2013, compared with 2012 reflects increased crude sales volumes, largely offset by lower prices. The increase in 2012, compared with 2011, reflected higher prices almost offset by lower volumes and foreign exchange losses.

In 2013 RC profit before interest and tax for the segment was $2.9 billion (2012 $2.9 billion, 2011 $5.5 billion). The 2013 result included a net non-operating charge of $535 million, primarily relating to impairment charges in our fuels business, versus charges of $3,172 million in 2012 mainly related to impairment charges and $602 million in 2011 for impairment charges associated with our disposal programme, partially offset by gains on disposal. In addition, fair value accounting effects had an unfavourable impact of $178 million in 2013 versus an unfavourable impact of $427 million in 2012 and a favourable impact of $63 million in 2011.

After adjusting for non-operating items and fair value accounting effects, underlying RC profit before interest and tax was $3.6 billion (2012 $6.5 billion, 2011 $6.0 billion).

The fuels business delivered an underlying RC profit before interest and tax of $2,230 million for the year (2012 $5,012 million, 2011 $3,639 million). Compared with 2012, 2013 saw significantly weaker refining margins. Margins were weakened by reduced throughput due to the planned crude unit outage at our Whiting refinery and commissioning of the new units that were part of the refinery modernization project and the absence of earnings from the divested Texas City and Carson refineries. This was partially offset by a significantly improved supply and trading contribution and lower overall turnaround activity during the year. Compared with 2011, the 2012 result reflected strong operations that enabled us to capture the higher refining margin environment, partly offset by a lower supply and trading contribution.

The lubricants business delivered an underlying RC profit before interest and tax of $1,272 million for the year (2012 $1,285 million, 2011 $1,250 million). These results reflect sustained underlying performance for the lubricants business.

The petrochemicals business delivered an underlying RC profit before interest and tax of $130 million for the year (2012 $166 million, 2011 $1,120 million). Compared with 2012, the 2013 result reflected weaker product margins resulting from over supply in certain markets partially offset by lower turnaround activity in the US and Europe.

Our petrochemicals production[a] of 13,943 thousand tonnes (kte) in 2013 was lower than the previous two years (2012 14,727kte, 2011 14,866kte) due to the sale of our BPCM Kuantan PTA plant in 2012 as well as reduced output in both years for commercial reasons given the low-margin environment.

A summary of our interests in petrochemicals production capacity as at 31 December 2013 is provided on page 244.

[a] Petrochemicals production includes 1,494kte of petrochemicals produced at our Gelsenkirchen and Mülheim sites in Germany for which the income is reported in our fuels business.

Our fuels business

The fuels strategy focuses largely on fuels value chains (FVCs) which include large-scale, highly upgraded and feedstock advantaged refineries that are integrated with logistics and marketing as well as fuels marketing businesses primarily supplied by our global supply and trading organization.

The FVCs seek to optimize the activities of our assets across the supply chain through: advantaged feedstock 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.

Refining

At 31 December 2013 we owned or had a share in 14 refineries producing refined petroleum products that we supply to retail and commercial customers. A summary of our interests in refineries and average daily crude distillation capacities as at 31 December 2013 is provided on page 243. As part of our plan to reshape BP s US fuels business, we completed the sales of the Texas City and Carson, California refineries and associated logistic and marketing assets.

The Texas City refinery and a portion of our retail and logistics network in the south-east US were sold to Marathon Petroleum Corporation on 1 February 2013 for consideration of up to $2.5 billion. On 3 June 2013 we completed the sale of the Carson refinery in California, ARCO network and related regional logistics assets to Tesoro Corporation for approximately $2.4 billion.

Strategic investments in our refineries are focused on maintaining the safety and reliability of our assets while improving unit margins versus the competition. The most important of these strategic investments in 2013 was the Whiting refinery modernization project. During the year the new coker, crude oil unit, gasoil hydrotreater, and an upgraded sulphur recovery complex were all commissioned. We plan to progressively ramp up heavy crude processing to approximately 280,000 barrels per day during the second quarter of 2014. This major investment transforms Whiting into one of the key advantaged downstream assets in our portfolio, with the capacity to process a greater proportion of heavy crudes, and underpins our ability to deliver increased cash flow from 2014 onwards.

Refinery operations were strong this year, with Solomon refining availability of 95.3%. Utilization rates were at 86% principally due to the planned crude unit outage at our Whiting refinery as part of the modernization project. Overall refinery throughputs in 2013 were lower than those in 2012, mostly driven by the divestment of the Texas City and Carson refineries and associated logistics and marketing activities in 2013.

Table of Contents

	thousand barrels per day		
Refinery throughputs[a]	**2013**	2012	2011
US	**726**	1,310	1,277
Europe	**766**	751	771
Rest of world	**299**	293	304
Total	**1,791**	2,354	2,352
			%
Refining availability[b]	**95.3**	94.8	94.8
	thousand barrels per day		
Sales volumes			
Marketing sales[c]	**3,084**	3,213	3,311
Trading/supply sales[d]	**2,485**	2,444	2,465
Total refined product sales	**5,569**	5,657	5,776
Crude oil[e]	**2,142**	1,518	1,532
Total	**7,711**	7,175	7,308

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

[b] 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.

[c] 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.

[d] Trading/supply sales are sales to large unbranded resellers and other oil companies.

[e] 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. Fifty-nine thousand barrels per day relate to revenues reported by the Upstream segment.

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, where we seek to drive excellence in operational and transactional processes, and deliver compelling customer offers in the various markets in which we operate.

We blend and market biofuels in our FVCs; almost 6.5 billion litres of biofuels were blended into finished product in 2013, mainly in Europe and the US. Biogasoline (bioethanol) and biodiesel (hydrogenated vegetable oils and fatty acid methyl esters) demand continues to grow, primarily in Europe and the US, as regulatory requirements demand higher blending levels. In response we continue to develop blend capabilities and to work with regulators, biofuels suppliers and other stakeholders to improve the sustainability of the biofuels we blend and supply.

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. In addition, we supply commercial customers within the transport and industrial sectors.

	Number of retail sites operated under a BP brand		
Retail sites[f]	**2013**	2012	2011
US	**7,700**	10,100	11,300

Europe	**8,000**	8,300	8,200
Rest of world	**2,100**	2,300	2,300
Total	**17,800**	20,700	21,800

[f] 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.* Excludes our interests in equity-accounted entities that are dual-branded.

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 function (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 Downstream 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. 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 by entering into a full range of exchange-traded commodity derivatives, over-the-counter (OTC) contracts and spot and term contracts. 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 s risk governance framework seeks to manage and oversee the financial risks associated with this trading activity, which is described in Financial statements Note 19.

The range of contracts that the group enters into is described in Certain definitions commodity trading contracts on page 270.

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 sectors. We have marketing sales in excess of 465,000 barrels per day. Air BP s strategic aim is to maintain its position in the core locations of Europe and the US, while expanding its portfolio in airports that offer long-term competitive advantage in material growing markets such as Asia and South America.

LPG

We have neared completion of the sale of our global LPG marketing business, which sells bulk and bottled LPG products. We will retain focus on LPG when it is deeply integrated in refinery operations and autogas sectors in order to optimize refinery and retail operations. As of 31 December 2013, the sales of the LPG business in six out of eight countries had been completed. The remaining two countries are expected to be completed in 2014.

Our lubricants business

Our strategy is to leverage technology, brand, and relationships, with a focus on our premium brands, to deliver growth and sustainable returns.

Our lubricants business manufactures and markets lubricants and related products and services to the automotive, industrial, marine, aviation and energy markets across the world. 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.

We are one of the largest purchasers of base oil in the market, but have chosen not to produce at scale in base oil or additives manufacturing. Our participation in the value chain is focused on areas of competitive differentiation and strength. These fall into three main areas:

We develop formulation and the application of cutting-edge technologies.

We create and develop product brands and clearly communicate their benefits to our customers.

We build and extend our relationships with customers so we can better understand and meet their needs.

In 2013, the automotive sector saw signs of recovery in new passenger vehicle demand across several key markets including China, the US and certain European countries. For 2013, lubricants base oil prices averaged below 2012, which benefited margins. A significant share of profit growth has come from emerging markets, where we are developing a strong base to capture further growth.

The global lubricants market remained challenging in 2013 as a result of economic slowdown and low demand growth. The automotive sector saw declines in new passenger vehicle demand across Europe and India, which were partially offset with growth in North America, China and Brazil. Industrial demand remained under pressure from a weak manufacturing sector.

We continue to increase lubricants revenues through our strategy of exposure to growing markets, technology investments and targeted marketing programmes. More than 35% of sales revenues were from non-OECD countries in 2013.

Our lubricants business continued to increase the proportion of total sales resulting from premium product sales; in 2013 the percentage of premium sales was 40% compared with 39% in 2012 and 37% in 2011.

In January 2014, BP announced that it had agreed to sell its specialist global aviation turbine oils business. The transaction, which is subject to regulatory and other approvals, is expected to be completed in the second quarter of 2014.

Our petrochemicals business

Our strategy is to own and develop petrochemical value chain businesses which are built around proprietary technology. We apply this technology to existing businesses and to access new growth markets where we wish to build material shares. Overall, the business targets attractive absolute returns and material, increasing cash flows by satisfying demand growth, particularly in Asia.

We manufacture and market four main product lines:

- Purified terephthalic acid (PTA).
- Paraxylene.
- Acetic acid.
- Olefins and derivatives.

We also produce a number of other speciality petrochemicals products.

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 leading to losses for the older, less efficient producers. New capacity additions are targeted principally in the higher-growth Asian markets.

We both own and operate assets, and have also invested in a number of joint arrangements in Asia, where our partners are leading companies within their domestic market. For example, the construction of our new, third PTA plant with our partner, Zhuhai Port Co. in Guangdong, China is progressing well and is planned to begin production in late 2014. The retro-fit of key elements of our PTA technology to existing plants is under way. We expect these investments to have a material impact on efficiency and reduce annual operating costs.

Our technology team develops, deploys and optimizes chemicals technology to advance the competitiveness of the installed asset base and deliver competitively advantaged projects to access growth. We plan to continue deploying our technology in new asset platforms to access Asian demand and advantaged feedstock sources.

In 2013 we announced two new proprietary petrochemicals technologies, *SaaBre* and *Hummingbird*. *SaaBre* significantly reduces the cost of production of acetic acid from syngas and avoids the need to purify carbon monoxide or purchase methanol. *SaaBre* technology could also be used to produce methanol and ethanol. *Hummingbird* simplifies the process of converting ethanol to ethylene, a key component for the manufacture of plastics. *Hummingbird* could open the way for the production of biopolymers from bioethanol. Both technologies are expected to deliver significant reductions in variable manufacturing costs and simplify the manufacturing process.

In December 2013, we agreed to purchase all interests held by our partners, Mitsui Chemicals, Inc. (MCI) and Mitsui & Co. Ltd. (MBK) in PT Amoco Mitsui PTA Indonesia (AMI) which produces and markets PTA in the Republic of Indonesia. This transaction completed on 28 February 2014 and is consistent with our strategy of growing our PTA business in our chosen markets.

In September 2013, we signed a non-binding memorandum of understanding with Oman Oil Corporation to assess jointly a facility in Oman for the manufacture of acetic acid, deploying our *SaaBre* technology.

The economic environment for some of our products is likely to remain under pressure in 2014. The impact of capacity additions in Asia continues to depress margins for PTA. The environments for our acetic acid and olefins and derivative value chains are expected to improve in the latter part of 2014 as the high growth markets absorb excess capacity.

Rosneft

In March 2013 BP completed sale and purchase agreements with Rosneft and Rosneftegaz.

Central processing and pumping facility at the Yuganskneftegaz field, onshore Russia.

BP and Rosneft

BP sold its investment in TNK-BP in exchange for $11.8 billion in cash and an 18.5% stake in Rosneft. Together with its existing 1.25% shareholding, BP now holds a 19.75% stake in the company.

BP s shareholding in Rosneft allows us to benefit from a diversified set of existing and potential projects in the Russian oil and gas sector. BP considers Rosneft share price appreciation and dividend growth as primary sources of value for its shareholders.

Rosneft s strategy is to pursue sustainable growth of crude oil production, develop its gas business and complete its refinery modernization programme.

BP is positioned to contribute to Rosneft s strategy through the sharing of technology, people, processes and best practice. We also have the potential to undertake standalone projects with Rosneft, both in Russia and internationally.

Bob Dudley was elected to the Rosneft board of directors in June 2013, and became a member of the Rosneft board s strategic planning committee.

Rosneft 2013 summary

Rosneft announced in June 2013 that it had completed the process of integrating TNK-BP and subsequently the Rosneft board approved a modified business plan for 2013 incorporating the acquisition of TNK-BP.

Rosneft concluded long-term crude oil supply agreements with China National Petroleum Corporation (CNPC) and Sinopec, signalling China as an additional market for Russian crude.

Rosneft completed the acquisition of the remaining 49% in the Itera joint venture, 51% of Sibneftegaz and agreed to buy gas assets from ALROSA.

Rosneft made a voluntary offer in October 2013 to buy out the non-controlling shareholders of RN Holding (formerly TNK-BP Holding). By the closing date of the offer in January 2014, Rosneft had received acceptances of its offer from over 98% of such shareholders.

Table of Contents

Upstream

Rosneft is the largest oil company in Russia and the largest publicly traded oil company in the world based on hydrocarbon production volume. Rosneft also has significant hydrocarbon reserves.

Rosneft has assets in all key hydrocarbon regions of Russia: Western Siberia, Eastern Siberia, Timan-Pechora, Volga-Urals, North Caucasus and Far East. Internationally, Rosneft participates in exploration projects or has operations in countries including the US, Canada, Vietnam, Venezuela, Brazil, Algeria, UAE, Kazakhstan and Norway. Rosneft and Gazprom, the majority of whose shares are owned by the Russian state, have exclusive rights to explore and develop significant hydrocarbon resources in the Russian Arctic offshore (including the Sea of Okhotsk). To progress Arctic exploration, Rosneft has concluded partnerships with ExxonMobil, ENI, Statoil, CNPC and Inpex.

In 2013 Rosneft signed new gas sales contracts with Enel, Fortum and others to monetize produced gas. Also Russian legislation introduced in December 2013 allows Rosneft and Novatek to export LNG for the first time.

Downstream

Rosneft has interests in 23 refineries including four in Germany through its Ruhr Oel GmbH partnership with BP. In 2013 Rosneft acquired a 21% share in the Saras S.p.A. refinery in Italy.

Rosneft refinery throughput in 2013 amounted to 1,818mb/d. Rosneft continues to implement its refinery modernization programme which is intended to significantly upgrade and expand its refining capacity. As at 31 December 2013, Rosneft owned and operated more than 2,400 retail service stations, representing the largest network in Russia. This included BP-branded sites acquired as part of Rosneft s acquisition of TNK-BP which will continue to operate under the BP brand. Rosneft s downstream operations also include jet fuel, bunkering, bitumen and lubricants.

Rosneft segment performance

BP s investment in Rosneft is managed and reported as a separate segment under IFRS. The Rosneft segment result includes equity-accounted earnings from Rosneft, representing BP s share in Rosneft and foreign currency effects on the dividends received in 2013. For more information on the sale and purchase agreements, see Financial statements Note 6.

	$ million
	2013[a]
Profit before interest and tax[b c]	**2,053**
Inventory holding (gains) losses	**100**
Replacement cost profit before interest and tax[c]	**2,153**
Net charge (credit) for non-operating items	**45**
Underlying replacement cost profit before interest and tax[c d]	**2,198**

[a] From 21 March 2013.

[b]

BP s share of Rosneft s earnings after finance costs, taxation and non-controlling interests is included in the BP group income statement within profit before interest and taxation.

[c] Includes $5 million of foreign exchange losses arising on the dividend received. This amount is not reflected in the following table.

[d] Underlying replacement cost profit is not a recognized GAAP measure. See footnote c on page 23 for information on underlying replacement cost profit.

Replacement cost profit before interest and tax for the Rosneft segment was $2.2 billion in 2013. The result included a net non-operating charge of $45 million, primarily relating to impairment charges. After adjusting for non-operating items, underlying replacement cost profit before interest and tax in 2013 was $2.2 billion.

BP received a dividend from Rosneft in 2013 of $456 million, after the deduction of withholding tax.

BP completed the exercise to determine the fair value of its share of Rosneft s assets and liabilities as at 21 March 2013, as required under IFRS, and the results of this exercise are reflected in the 2013 reported amounts.

BP s share of the components of Rosneft s net income are shown in the table below.

	$ million
	2013[a]
Income statement (BP share)	
Profit before interest and tax	**2,786**
Finance costs	**(264)**
Taxation	**(422)**
Non-controlling interests	**(42)**
Net income	**2,058**
Inventory holding (gains) losses, net of tax	**100**
Net income on a replacement cost basis	**2,158**
Net charge (credit) for non-operating items, net of tax	**45**
Net income on an underlying replacement cost basis	**2,203**

Balance sheet

	$ million
	31 December 2013
Investments in associates	**13,681**

Production and reserves

	2013
Production (net of royalties) (BP share)[e f]	
Liquids (mb/d)[g]	**650**
Natural gas (mmcf/d)	**617**
Total hydrocarbons (mboe/d)[h]	**756**
Estimated net proved reserves (net of royalties) (BP share)	
Liquids (million barrels)[g]	**4,975**
Natural gas (billion cubic feet)	**9,271**

Total hydrocarbons (mmboe)	**6,574**
Average oil marker prices	$ per barrel
Urals (Northwest Europe CIF)	**107.38**
Russian domestic oil	**54.97**

[e] Reflects production for the period 21 March to 31 December, averaged over the full year.
[f] Information on BP s share of TNK-BP s production for comparative periods is provided on pages 248 and 250.
[g] Liquids comprise crude oil, condensate and natural gas liquids.
[h] Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Table of Contents

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 including centralized functions.

Financial performance

			$ million
	2013	2012	2011
Sales and other operating revenues[a]	**1,805**	1,985	2,957
Replacement cost profit (loss) before interest and tax	**(2,319)**	(2,794)	(2,468)
Net (favourable) unfavourable impact of non-operating items	**421**	798	822
Underlying replacement cost profit (loss) before interest and tax[b]	**(1,898)**	(1,996)	(1,646)
Capital expenditure and acquisitions	**1,050**	1,435	1,853

[a] Includes sales to other segments.

[b] Underlying replacement cost profit (loss) is not a recognized GAAP measure. See footnote c on page 23 for information on underlying replacement cost profit (loss).

The replacement cost loss before interest and tax for the year ended 31 December 2013 was $2.3 billion (2012 $2.8 billion, 2011 $2.5 billion). The 2013 result included a net charge for non-operating items of $421 million (2012 $798 million, 2011 $822 million).

After adjusting for non-operating items, the underlying replacement cost loss before interest and tax for the year ended 31 December 2013 was $1.9 billion (2012 $2.0 billion, 2011 $1.6 billion). This result reflected higher income on cash balances and lower corporate costs. 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 costs.

Alternative Energy

BP is committed to alternative energy and our strategy is focused on operating large scale businesses and commercializing our innovative technologies. BP continues to invest in expanding the scale of our biofuels business and in leveraging our unique capabilities and experience in agri-business, bio-technology and bio-refining. We also have an operating wind business. As at 31 December 2013, we have invested approximately $8.3 billion[c], exceeding our 2005 commitment of $8 billion over 10 years.

[c] The majority of costs were initially capitalized, although some were expensed under IFRS.

Biofuels

BP believes that it has a key role to play in enabling the transport sector to respond to the dual challenges of energy security and climate change. We have 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/bbl crude oil environment without subsidies.

We operate three sugar cane mills in Brazil producing bioethanol and sugar, and exporting power to the grid. We continue to evaluate options to increase production at these facilities and have already started work on expanding ethanol production capacity at one mill and this work is expected to be completed in 2014. Likewise, we are ramping up production at our Vivergo joint venture plant, which is the largest bioethanol facility in the UK and one of the largest in Europe. Once up to full production capacity of 420 million litres per year, the Vivergo facility will represent around 20% of the UK s total 2012-13 requirements under the Renewable Transport Fuels Obligation (RTFO).

BP continues to invest throughout the entire biofuels value chain, from growing sustainable higher-yielding and lower-carbon feedstocks through to the development, production and marketing of the advantaged fuel molecule biobutanol, which has higher energy content than ethanol and delivers improved fuel economy.

In conjunction with its partner DuPont, BP is undertaking leading-edge research into the production of biobutanol under the company name Butamax.

Across our biofuels business, BP s share of ethanol-equivalent production[d] for 2013 was 521 million litres (552 million litres gross) compared with 404 million litres 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.

[d] Ethanol-equivalent production includes ethanol and sugar.

Wind

In wind power, our business is focused onshore in the US. In 2013 we marketed our wind business for sale. Despite receiving a number of bids, we determined it was not the right time to sell and instead are focusing on optimizing performance at our 16 wholly owned and joint-venture wind farms.

BP maintained its net wind generation capacity in the US at 1,558MW[e] during 2013. BP s net share of wind generation for 2013 was 4,203GWh (7,363GWh gross), compared with 3,587GWh (5,739GWh gross) a year ago.

[e] BP also has 32MW of wind capacity in the Netherlands, operated by our Downstream segment.

Emerging business and ventures

Our emerging business and ventures unit invests in technology entrepreneurs working at the frontiers of their fields across the entire energy spectrum. Investments focus on emerging, strategic technologies, oil and gas, downstream technologies including fuels and chemicals, and biotech and bioenergy. The unit has made 37 separate investments, with $210 million of committed capital.

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. In December 2013, BP announced it had signed a contract with Hyundai Mipo Dockyard Co., Ltd to build 14 new product tankers in Korea. The first of these will be delivered in 2016.

Treasury

Treasury manages the financing of the group centrally, ensuring liquidity is 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 Singapore, 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 and the short-term investment of operational cash balances. 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 19.

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 is reviewed on a regular basis and if specific circumstances require such a review.

Outlook

In 2014 Other businesses and corporate annual charges, excluding non-operating items, are expected to be in the range of $1.6-$2.0 billion.

Table of Contents

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.

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, continued to complete the Deepwater Horizon operational response activities. By the end of 2013, operational activity continued on just 37 of the approximately 4,400 shoreline miles in the area of response. These 37 shoreline miles were all in Louisiana and were subject to patrolling and maintenance, final monitoring or inspection, or were pending final Coast Guard approval at the end of 2013. The US Coast Guard ended active clean-up in Mississippi, Alabama and Florida in June 2013.

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.

Environmental restoration

BP is responsible for the reasonable and necessary costs of assessing potential injury to natural resources resulting from the oil spill as well as the reasonable and necessary costs of restoration as defined under the Oil Pollution Act of 1990. In 2013 activity was focused on natural resource damage assessment but some early restoration work has also begun.

Natural resource damage assessment

Scientists from BP, government agencies, academia and other organizations are studying a range of species and habitats to understand how wildlife populations and the environment may have been affected by the accident and oil spill. Since May 2010, more than 240 initial and amended work plans have been developed by state and federal trustees and BP to study resources and habitat. The study data will inform an assessment of injury to natural resources in the Gulf of Mexico and the development of a restoration plan to address the identified injuries. By the end of 2013, BP had paid approximately $1 billion to support the assessment process.

Early restoration projects

While the injury assessment is still ongoing, restoration work has begun. In April 2011 BP committed to provide up to $1 billion in early restoration funding to expedite recovery of natural resources injured as a result of the Deepwater Horizon accident and oil spill. BP and the trustees, as at December 2013, had reached agreement or agreement in principle on a total of 54 early restoration projects that are expected to cost approximately $698 million, including 10 projects that are already in place or under way.

Projects announced in 2013 include ecological projects that will restore habitat and resources, as well as projects that enhance recreational use of natural resources. These projects will proceed through a further regulatory review and public comment process. Once that process is complete, BP and the trustees will seek to proceed with approved projects. BP will provide project funding in exchange for restoration credit to be applied to the final assessment of natural resource damages.

Gulf of Mexico Research Initiative

In May 2010 BP 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. As at 31 December 2013, the aggregate contribution by BP was $169 million. The continued fulfilment of this commitment is one of the conditions of the US government criminal plea agreement (see below).

Economic recovery

BP continued to support economic recovery efforts in local communities through a variety of actions and programmes in 2013. By 31 December 2013, BP had spent $12.8 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. BP has committed $2.3 billion to help resolve economic loss claims related to the Gulf of Mexico seafood industry, of which $1.2 billion has been paid in to the seafood compensation fund but has not yet been distributed to final claimants.

Plaintiffs Steering Committee settlements

BP reached settlements in 2012 with the Plaintiffs Steering Committee (PSC) to resolve the substantial majority of legitimate individual and business claims and medical claims stemming from the accident and oil spill. The PSC acts on behalf of individual and business plaintiffs in the multi-district litigation proceedings in New Orleans (see Legal update below). During 2013, amounts paid out under the PSC settlements totalled $2.7 billion.

As part of its monitoring of payments made by the court-supervised settlement programme for the economic and property damages settlement, BP identified and disputed multiple business economic loss claim determinations that appeared to result from an incorrect interpretation of the economic and property damages settlement agreement by the claims administrator. See further details under Legal update below. BP has also raised issues about misconduct and inefficiency in the facility administering the settlement.

The medical benefits class action settlement provides for claims to be paid to qualifying class members from the agreement s effective date. Following the resolution of all appeals relating to this settlement, the agreement s effective date was 12 February 2014. The deadline for submitting claims under the settlement is one year from the effective date.

OPA claims programme

There is a separate BP claims programme which handles claims under the Oil Pollution Act of 1990 (OPA) by individuals and businesses who are not covered by the PSC economic and property damages settlement, who have opted out of the settlement or who are pursuing claims separately, as permitted by the terms of the settlement. During 2013, amounts paid out in relation to the OPA claims programme totalled $31 million.

State and local claims

Several states and local government entities have presented claims for alleged losses, including economic and property damage, under OPA. BP has provided for the current best estimate of the amount required to settle these obligations. BP considers most of these claims to be unsubstantiated and the methodologies used to calculate them to be seriously flawed, not supported by OPA, not supported by documentation and to be substantially overstated. A total of $89 million was paid in relation to state and local claims in 2013.

For further information on the PSC settlements and state and local claims, see Legal proceedings on page 257, Financial Statements Note 2 and *bp.com/uslegalproceedings*.

Table of Contents

Legal update

BP is subject to a number of different legal proceedings in connection with the Deepwater Horizon incident. These include the legal proceedings relating to the PSC settlements; the multi-district litigation proceedings in New Orleans; a range of civil lawsuits, including claims brought by states and local government entities; other civil claims by individuals and businesses; and the multi-district litigation proceedings in Houston in relation to alleged violations of securities legislation. In 2012, BP reached a settlement with the US Department of Justice relating to all federal criminal charges and a settlement with the SEC resolving certain civil claims. Certain BP entities have been subject to suspension and debarment by the US Environmental Protection Agency (EPA).

PSC settlements

There have been various rulings from the district court and the US Court of Appeals for the Fifth Circuit (Fifth Circuit) on matters relating to interpretation of the PSC economic and property damages settlement agreement, including the meaning of the causation requirements of the agreement.

In 2013 a panel of the Fifth Circuit (the business economic loss panel) set aside the claims administrator s interpretation of the business economic loss framework of the settlement agreement and instructed the district court in New Orleans to undertake additional proceedings to determine the correct interpretation of the agreement. In December 2013, the district court ruled that, for the purposes of determining business economic loss claims, revenues must be matched with expenses incurred by claimants in conducting their business even where the revenues and expenses were recorded at different times. The district court assigned the development of more detailed matching requirements to the claims administrator. The claims administrator has issued a draft policy addressing the matching of revenue and expenses for business economic loss claims. The parties have made written submissions on the draft policy and the claims administrator will issue a final policy to which BP and the PSC have the right to object and seek review by the district court.

The district court also ruled that the settlement agreement did not contain a causation requirement beyond the revenue and related tests set out in an exhibit to that agreement. BP appealed the district court s ruling on causation to the business economic loss panel, but the panel affirmed the district court s ruling on 3 March 2014. BP is considering its appeal options, including a potential petition that all the active judges of the Fifth Circuit review the 3 March decision. The temporary injunction on business economic loss claims offers and payments will be lifted when the case is transferred back to the district court; the timing of this would be affected by the status of any such petition by BP.

A separate but related appeal was brought by objectors to the economic and property damages settlement challenging the overall fairness and lawfulness of the agreement. This appeal was heard by a different panel of the Fifth Circuit, which, in January 2014, upheld the district court s approval of the settlement agreement and left to the business economic loss panel the question of how to interpret the agreement, including the meaning of the agreement s causation requirements. BP and several of the objectors have filed petitions requesting that all the active judges of the Fifth Circuit review the decision to uphold the approval of the settlement.

BP has filed a lawsuit alleging that it relied on fraudulent representations by a former PSC lawyer when negotiating aspects of the PSC settlement relating to the $2.3-billion seafood compensation fund. The district court granted the lawyer s motion to stay this lawsuit, pending developments in the government s criminal investigation and possible indictment. The district court also denied BP s motion requesting that further payments from the seafood compensation fund be suspended on the basis that no further payment from the fund is imminent. The district court deferred ruling on a motion by BP seeking to determine the extent of the fraud and what portion, if any, of the seafood fund should be returned as a result.

Multi-district litigation proceedings in New Orleans

The multi-district litigation trial relating to liability, limitation, exoneration and fault allocation (MDL 2179) began in the federal district court in New Orleans in February 2013. The first phase of the trial focused on the causes of the accident and the allocation of fault among the defendants. The second phase focused on efforts to stop the flow of oil and the volume of oil spilled. BP is not aware of the timing of the district court s rulings in respect of these first two phases of the trial and the court could issue its decision at any time.

In a subsequent trial phase, for which no trial date has yet been set, the district court will consider the statutory per-barrel penalty rate to be applied in determining penalties under the Clean Water Act. There is significant uncertainty about the amount of Clean Water Act penalties to be paid, and the timing of payment, as these will depend on the finding as to negligence or gross negligence, the volume of oil spilled and the application of statutory penalty factors. The district court has wide discretion in its determination as to whether a defendant s conduct involved negligence or gross negligence as well as in its determinations on the volume of oil spilled and the application of statutory penalty factors.

Civil claims

BP p.l.c., BP Exploration & Production Inc. (BPXP the BP group company that conducts exploration and production operations in the Gulf of Mexico) and various other BP entities have been among the companies named as defendants in approximately 2,950 civil lawsuits resulting from the accident and oil spill, including the claims by several states and local government entities referred to above. The majority of these lawsuits assert claims under OPA, as well as various other claims, including for economic loss and real property damage, and claims under maritime law and state law. These lawsuits seek various remedies including economic and compensatory damages, punitive damages, removal costs and natural resource damages. Many of the lawsuits assert claims excluded from the PSC settlements, such as claims for recovery for losses allegedly resulting from the 2010 federal deepwater drilling moratoria and the related permitting process. Many of these lawsuits have been consolidated with the multi-district litigation proceedings in New Orleans.

Multi-district litigation proceedings in Houston

The MDL 2185 proceedings pending in federal court in Houston, including a purported class action on behalf of purchasers of American Depository Shares under US federal securities law, are continuing. A jury trial is scheduled to begin in October 2014.

SEC settlement

In connection with the 2012 settlement with the SEC resolving the SEC s Deepwater Horizon-related civil claims, as of 31 December 2013, BP had completed its first two payments totalling $350 million. A final $175 million payment, plus accrued interest, is scheduled for 2014.

US government criminal plea agreement

Under the terms of the criminal plea agreement reached with the US government in 2012 to resolve all federal criminal claims arising out of the Deepwater Horizon incident, BP is taking additional actions, enforceable by the court, to further enhance the safety of drilling operations in the Gulf of Mexico. The first annual update on BP s compliance with the plea agreement is expected to be available by 31 March 2014 and to be published at *bpxpcompliancereports.com*.

The plea agreement also provides for the US government to appoint two independent monitors a process safety monitor and an ethics monitor as well as an independent third-party auditor. The process safety monitor has been retained, for a period of up to four years from February 2014, and will review and provide recommendations concerning BPXP s process safety and risk management procedures for deepwater drilling in the Gulf of Mexico. The ethics monitor has been retained, for a term of up to four years from 2013, and will review and provide recommendations concerning BP s ethics and compliance programme. The third-party auditor has also been retained and will review and report to the probation officer, the US government and BP on BPXP s compliance with the plea agreement s implementation plan.

US Environmental Protection Agency (EPA) suspension and debarment

In November 2012, the EPA suspended BP p.l.c., BPXP and other BP companies from receiving new federal contracts or renewing existing ones. In 2013, the EPA debarred the Houston headquarters of BPXP, thus effectively preventing it from entering into new contracts or leases with the US government. In November 2013, the EPA continued the suspensions of the previously suspended companies, suspended two new BP entities and proposed discretionary debarment of all suspended BP entities. BP is challenging the EPA s suspension and debarment decisions. Neither the suspensions nor the proposed debarments 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. BP continues to work with the EPA in preparing an administrative agreement to resolve these suspension and debarment issues.

For further information on these matters, see Risk factors on page 51 and Legal proceedings on page 257.

Financial update

The group income statement for 2013 includes a pre-tax charge of $469 million in relation to the Gulf of Mexico oil spill. The charge for the year reflects adjustments to provisions and the ongoing costs of the Gulf Coast Restoration Organization. As at 31 December 2013, the total cumulative charges recognized to date amount to $42.7 billion. BP has provided for spill response costs, environmental expenditure, litigation and claims and Clean Water Act penalties that can be measured reliably. At 31 December 2013, provisions related to the Gulf of Mexico oil spill amounted to $9.3 billion (2012 $15.2 billion).

The cumulative income statement charge does not include amounts for obligations that BP considers are not possible, at this time, to measure reliably. Nothing is currently provided for natural resource damages, except for $1 billion for early restoration projects and no provision has been made for amounts arising from MDL 2185 (securities class action). In addition, management believes that no reliable estimate can be made of any business economic loss claims not yet received, processed and paid. This is because of the significant uncertainties which exist currently, as noted in the Plaintiffs Steering Committee section above (see also Financial statements Note 2). The additional amounts payable for these and other items (such as state and local claims) could be considerable.

The total amounts that will ultimately be paid by BP in relation to all the obligations relating to the accident and oil spill are subject to significant uncertainty. The ultimate exposure and cost to BP will be dependent on many factors, including any new information or future developments. These could have a material impact on our consolidated financial condition, results of operations and cash flows. The risks associated with the accident and oil spill could also heighten the impact of the other risks to which the group is exposed.

For details regarding the impacts and uncertainties relating to the Gulf of Mexico oil spill, see Risk factors on page 51 and Financial statements Note 2.

Deepwater Horizon Oil Spill 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. The Trust was fully funded by the end of 2012.

Payments made out of the Trust during 2013 totalled $3.1 billion for individual and business claims, medical settlement programme payments, natural resource damage assessment and early restoration, state and local government claims, costs of the court supervised settlement progamme and other resolved items. As at 31 December 2013, the aggregate cash balances in the Trust and the associated qualified settlement funds amounted to $6.7 billion, including $1.2 billion remaining in the seafood compensation fund, which is yet to be distributed, and $0.9 billion held for natural resource damage early restoration projects.

As at 31 December 2013, the cumulative charges to the Trust amounted to $19.3 billion. Thus, a further $0.7 billion could be charged in subsequent periods for items covered by the Trust with no net impact on the income statement. Additional liabilities in excess of this amount would be expensed to the income statement. See Legal proceedings on page 257 and Financial statements Note 2 for more information.

Clean Water Act penalties

BP has recognized a provision of $3.5 billion for the estimated civil penalties for strict liability under the Clean Water Act, which are based on a specified range per barrel of oil released. The penalty rate per barrel used to calculate this provision is based upon BP s conclusion, among other things, that it did not act with gross negligence or engage in wilful misconduct.

If BP is found to have been grossly negligent, the penalty is likely to be significantly higher than the amount currently provided. See further details under Multi-district litigation proceedings in New Orleans above and in Financial statements Note 2.

Table of Contents

Corporate responsibility

We believe we have a positive role to play in shaping the long-term future of energy.

Fire safety training in Angola.

Safety

We continue to promote deep capability and a safe operating culture across BP.

Group safety performance

In 2013 BP reported six fatalities. These were four employees in the terrorist attack at In Amenas, Algeria and two contractors in heavy goods vehicle incidents, one in Brazil and one in South Africa. We deeply regret the loss of these lives.

Personal safety performance

		2013	2012	2011
Recordable injury frequency (group)	incidents per 200,000 hours worked	**0.31**	0.35	0.36
Day away from work case frequency[b] (group)	incidents per 200,000 hours worked	**0.070**	0.076	0.090

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

Process safety performance

	2013	2012	2011
Tier 1 process safety events	**20**	43	74
Loss of primary containment number of all incidents[c]	**261**	292	361
Loss of primary containment number of oil spills[d]	**185**	204	228

Number of oil spills to land and water	**74**	102	102
Volume of oil spilled (thousand litres)	**724**	801	556
Volume of oil unrecovered (thousand litres)	**261**	320	281

[c] Does not include either small or non-hazardous releases.
[d] Number of spills greater than or equal to one barrel (159 litres, 42 US gallons).
We report tier 1 process safety events defined as 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. We use the American Petroleum Institute (API) RP-754 standard. Our loss of primary containment (LOPC) metric 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. We seek to record all LOPCs regardless of the volume of the release and report on losses over a severity threshold.

Managing safety

We are working to continuously improve safety and risk management across BP. Three objectives guide our efforts:

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

Within BP, operating businesses are accountable for delivering safe, compliant and reliable operations. They are supported in this by our safety and operational risk (S&OR) function whose role is to:

- Set clear requirements.
- Maintain an independent view of operating risk.
- Provide deep technical support to the operating businesses.
- Intervene and escalate as appropriate to cause corrective action.

Governance

BP reviews risks at all levels of the organization. Each business segment has a safety and operational risk committee, chaired by the business head, to oversee the management of safety and risk in their respective areas of the business. In addition, the group operations risk committee (GORC) reviews safety and risk management across BP.

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 GORC s work. GORC also provides SEEAC with updates on BP s process and personal safety performance, and the monitoring of major incidents and near misses across the group. See Our management of risk on page 49.

Table of Contents

Operating management system (OMS)

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.

All BP businesses covered by the OMS are required to progressively align with this framework through an annual performance improvement cycle. Recently acquired operations need to transition to the OMS as the initial step in this process. The application of a comprehensive management system such as OMS across a global company is an ongoing process. See page 44 for information about joint arrangements.

Capability development

BP s capability development programmes are designed to equip our staff with the skills needed to run safe and efficient operations. The programmes cover our OMS, process safety and risk and safety leadership. Our global wells institute offers courses in areas such as applied deepwater well control, drilling engineering and well site leadership with more than 100 sessions delivered in 2013. It includes a simulator facility and an applied deepwater well control course where drilling personnel, including our contractors, can work together and practice a variety of well control situations. Trainers include experts from both inside and outside of the oil and gas industry.

Security and crisis management

The scale and spread of BP s operations means we must prepare for a range of potential business disruptions and emergency events. BP monitors for and aims to guard against hostile actions that could cause harm to our people or disrupt our operations, including physical and digital threats and vulnerabilities.

We also maintain disaster recovery, crisis and business continuity management plans and work to build day-to-day response capabilities to support local management of incidents and group-wide practices and response techniques. See page 44 for information on BP s approach to oil spill preparedness and response.

In January 2013, the In Amenas gas plant in Algeria, which is run as a joint operation between BP, Sonatrach (the national gas company of Algeria) and Statoil, came under armed terrorist attack. A total of 40 people from 10 countries and 10 organizations were killed in the attack. Four employees and a former employee lost their lives in the incident. BP and Statoil jointly carried out an extensive review of security arrangements in Algeria following the attack and we are working with Sonatrach on implementing a programme of security enhancements.

Safety in the Upstream business

In our Upstream business the recordable injury frequency for 2013 remained stable at 0.32, the same as in 2012. Our day away from work case frequency, incidents that resulted in an injury where a person is unable to work for a day (shift) or more, was 0.068 in 2013 compared to 0.053 in 2012. The number of reported loss of primary containment (LOPC) incidents was 143, down from 151 in 2012.

Safer drilling

Our global wells organization (GWO) is responsible for planning and executing our wells operations across the world. It brings wells expertise into a single organization to drive standardization and consistent implementation. It is also responsible for establishing new GWO standards on compliance, risk management, contractor management, performance indicators, technology and capability.

We have been developing and finalizing OMS conformance plans for activities which represent the highest risk areas in our wells operations. For example we have developed and applied new and revised engineering technical practices for activities such as well barriers and testing.

The Bly Report recommendations

BP s investigation into the Deepwater Horizon accident in 2010, the Bly Report, made 26 recommendations aimed at further reducing risk across BP s global drilling activities. They included strengthening contractor management, improving assurance on blowout preventers, well control, pressure-testing for well integrity, emergency systems, cement testing, rig audit and verification, and personnel competence.

At the end of 2013, 15 of the Bly Report recommendations had been completed. All 26 recommendations have been worked on in parallel and progress has been made towards each of them. By the end of 2013, over 75% of the deliverables that make up the 26 recommendations had been completed. A recommendation is defined as complete when it has been approved by senior management in our global wells organization and submitted for internal verification.

The outstanding recommendations relate to well control and well integrity, drilling and competence, the management of risk and change, and blowout preventers.

The board s safety, ethics and environment assurance committee monitors BP s global implementation of the measures recommended in the Bly Report, and progress is tracked quarterly by executive

Table of Contents

management. For the full report and periodic updates on progress see *bp.com/internalinvestigation*.

The Bly Report independent assessment

The BP board appointed Carl Sandlin as independent expert to provide an objective assessment of BP s global progress in implementing the deliverables from the Bly Report.

As part of his work, Mr Sandlin visited the regional wells teams with active operation twice in 2013. During each visit Mr Sandlin conducted reviews with their senior management and held discussions with key wells personnel and drilling contractors onsite.

The BP board and Mr Sandlin have agreed, in principle, that his engagement, initially scheduled to finish in June 2014, will be extended to June 2016.

Process safety monitor

Following legal settlements with the US government in 2012, BP has retained a process safety monitor for a term of up to four years from February 2014. The process safety monitor will review and provide recommendations concerning BP Exploration & Production Inc s process safety and risk management procedures for deepwater drilling in the Gulf of Mexico.

Sharing lessons learned

We continue to share what we have learned to advance global deepwater capabilities and practices that enhance safety in our company and the deepwater industry. We have conducted more than 200 briefings over the past three years to share lessons learned. We have worked with a range of industry partners including trade associations, host governments, national oil companies and regulators. For example we are working with the International Association of Oil & Gas Producers, Marine Well Containment Company, API and the International Association of Drilling Contractors.

Safety in the Downstream business

The process safety incident index (PSII) is a weighted index that reflects both the number and severity of events per 200,000 hours worked. In 2013 our PSII was down 60% compared to a baseline year of 2009. There were 101 LOPCs in 2013 down from 117 in 2012, with divestments accounting for a significant part of this reduction.

We measure personal safety performance through recordable injury frequency (RIF) and day away from work case frequency (DAFWCF) as well as severe vehicle accident rate (SVAR). In 2013 our RIF was 0.25 compared to 0.33 in 2012. The 2013 DAFWCF, the number of cases where an employee misses one or more days from work per 200,000 hours worked, was 0.063 compared to 0.089 in 2012.

Our SVAR which is the number of vehicle incidents that result in death, injury, a spill, a vehicle rollover, or serious disabling vehicle damage per one million kilometres travelled, was 0.10 in 2013 compared to 0.16 in 2012. Driving safety remains an area of focus for us.

We focus on the safe storage, handling and processing of hydrocarbons in our facilities across the Downstream business. 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.
- Provide safe locations, emergency procedures and other mitigation measures in the event of a release, fire or explosion.

Some areas where we worked to manage risks in our refining and petrochemicals portfolio in 2013 included:

- Corrosion: Improving the way we detect, measure and monitor corrosion with the aim of reducing the risk of leaks and increasing the reliability of our equipment. We are using industry benchmarks and technology to improve routine detection.
- Coaching: Nine manufacturing facilities participated in the Exemplar programme which aims to help sites apply our operating management system using continuous improvement processes.
- Site occupied buildings: We moved workforce further away from higher risk processing areas at our petrochemical plant in Zhuhai, China and installed an improved evacuation alert system at our chemical plant in Hull in the UK, as part of a multi-year programme.

Process safety expert for our Downstream business

The board s safety, ethics and environment assurance committee appointed Duane Wilson in May 2012 as process safety expert and assigned him to work in a global capacity with the Downstream business. In his role as process safety expert, Mr Wilson provides an independent perspective on the progress that BP s fuels, lubricants and petrochemicals businesses are making globally toward becoming industry leaders in process safety performance. Mr Wilson s contract has been extended to April 2015.

Working with partners and contractors

BP, like all our industry peers, rarely works in isolation we need to work with suppliers, contractors and partners to carry out our operations. In 2013, 54% of the 373 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 and contractors. To this end we set operational standards through legally-binding agreements. Training and dialogue also help build the capability of our contractors.

Contractors

We expect our contractors to comply with legal and regulatory requirements and to operate consistently with the principles of our code of conduct when working on our behalf. Our OMS includes requirements

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A contractor checks a pump in the production module on the Thunder Horse platform in the Gulf of Mexico, US.

and practices for working with contractors and our operations are obliged to plan and execute actions to reach conformance with OMS on contractor management.

We seek to set clear and consistent expectations of our contractors. In our Upstream business our standard model contracts include, for example, health, safety, security and environmental requirements.

Bridging documents are necessary in some cases to define how our safety management system and that of our contractors co-exist to manage risk on the work site.

In 2011 we undertook a review of how we manage contractors in our Upstream business, which examined best practice in BP and other industries that use contractors to perform potentially high-consequence activities. As a result of this review, we are focusing on developing deeper, longer-term relationships with selected contractors in our Upstream business. We have:

- Established global agreements that help to strengthen our relationships with strategic contractors and suppliers, manage risks more effectively and leverage economies of scale.
- Increased the rigour of health and safety qualification and selection criteria when approving contractor and supplier capabilities.
- Piloted guidance for the operating line on parts of our OMS that relate to working with contractors.
- Continued working with our strategic contractors and suppliers to create standardized technical specifications and quality requirements for certain equipment, initially focused on new projects.
- Worked on incorporating safety and quality key performance metrics into contracts for potentially high-consequence activities.

Our partners in joint arrangements

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 arrangement is linked to the size of our financial stake compared with other participants. Our code of conduct provides that we will do everything we reasonably can to make sure joint arrangements follow similar principles to those in our code. In some joint arrangements 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 arrangement.

In other cases, one of our joint arrangement partners may be the designated operator, or the operator may be an incorporated joint arrangement 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.

We introduced a group policy in 2013 to provide a consistent framework for identifying and managing BP s exposure related to safety and operational risk, as well as bribery and corruption risk, from our participation in new and existing non-operated joint arrangements.

Environment and society

Throughout the life cycle of our projects and operations, we aim to manage the environmental and social impacts of our presence.

Managing our impacts

At a group level, we review our management of material issues such as GHG emissions, water, oil spill response, sensitive and protected areas and human rights annually. Using our operating management system (OMS), we seek to identify emerging risks and assess methods to reduce them across the company.

Our OMS includes environmental and social practices that set out how our major projects identify and manage environmental and social impacts. The practices 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 to identify the most significant environmental and social impacts. Projects are required to identify mitigation measures and implement these in design, construction and operations. From April 2010 to the end of 2013, 91 projects had completed the screening process, and used outputs from the process to implement measures to reduce negative impacts.

BP s environmental expenditure in 2013 totalled $4,288 million (2012 $7,230 million, 2011 $8,491 million). This figure includes a credit of $66 million relating to the Gulf of Mexico oil spill. For reference, expenditure related to the Gulf of Mexico oil spill was a charge of $919 million in 2012 and $1,838 million in 2011. See page 252 for a breakdown of environmental expenditure. See Regulation of the group s business Environmental regulation on page 254.

Oil spill preparedness and response

We issued new group-wide requirements for oil spill preparedness and response planning, and crisis management in July 2012. These incorporate what we have learned from the Deepwater Horizon accident. All of our businesses that have the potential to spill oil have been updating oil spill planning scenarios and response strategies in line with the requirements.

Meeting the requirements is a substantial piece of work and we believe this work has already resulted in a significant increase in our oil spill response capability. For example, this includes using specialized modelling techniques and the provision of response capabilities, such as stockpiles of dispersants and planning for major offshore recovery operations.

Enhancing response capabilities

Improving our existing oil spill modelling tools helps BP to better define different oil spill scenarios and associated response plans. For example, following modelling for exploration in the Omani desert, we modified the planned location of pipelines to reduce the impact to groundwater if a spill were to occur.

We consider the environmental and socio-economic sensitivities of a region to help inform oil spill response planning. Sensitivity mapping helps us to identify the various types of habitats, resources and communities that could potentially be impacted by oil spills and develop appropriate response strategies. Sensitivity mapping is conducted around the world and in 2013 we updated sensitivity maps in Angola, Australia, Azerbaijan, Egypt, Libya, Trinidad & Tobago and the UK.

The use of dispersants is an important option in oil spill response planning. We have gained a greater understanding of dispersants and their use as a response option through scientific research programmes. We are examining topics such as the effectiveness of dispersants in the deep ocean and the efficiency of naturally occurring marine microbes to degrade dispersed oil in the Gulf of Mexico and in the seas of Australia, Azerbaijan and Egypt.

We seek to work collaboratively with government regulators in planning for oil spill response, with the aim of improving any potential future response. For example, in 2013 we shared lessons on dispersant use, controlled burning response strategies and oil spill modelling with government regulators in Azerbaijan, Brazil and Libya.

See page 42 for information on progress on the recommendations of BP s internal investigation into the Deepwater Horizon accident.

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 taking a number of practical steps, such as increasing energy efficiency in our operations, factoring a carbon cost into the investment and engineering decisions for new projects, and investing in lower-carbon energy products. We also require our operations to incorporate energy use considerations in their business plans and to assess, prioritize and implement technologies and systems to improve energy usage.

Climate change adaptation

We consider and identify risks and potential impacts of a changing climate on our facilities and operations. Where climate change impacts are identified as a risk for a new 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.

Greenhouse gas emissions

We report on GHG emissions on a carbon dioxide-equivalent (CO_2e) basis. This includes CO_2 and methane for direct emissions and CO_2 for indirect emissions, which are associated with the purchase of electricity, heat or steam into our operations. Our GHG reporting encompasses all BP s consolidated entities as well as our share of equity-accounted entities other than BP s share of TNK-BP and Rosneft. Rosneft s emissions data can be found on its website.

Our approach to calculating GHG emissions is aligned with the Greenhouse Gas Protocol and the IPIECA/API/OGP Petroleum Industry Guidelines for Reporting GHG Emissions. We calculate emissions based on the fuel consumption and fuel properties for major sources rather than the use of generic emission factors. We do not include nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride as they are not material and therefore it is not practical to collect this data.

Greenhouse gas emissions

	2013	2012	2011
Direct GHG emissions (Mte CO_2e)	**49.2**	59.8	61.8
Indirect GHG emissions (Mte CO_2e)	**6.6**	8.4	9.0

The decrease in our direct GHG emissions is primarily due to the divestment of our Texas City and Carson refineries.

Intensity

The ratio of our total greenhouse gas emissions to adjusted revenue of those entities (or share of entities) included in our GHG reporting was 0.15kte/$million in 2013. Adjusted revenue reflects total revenues and other income, less gains on sales of businesses and fixed assets. Additionally, we publish the ratios for greenhouse gas emissions to upstream production, refining throughput and chemicals produced at *bp.com/greenhousegas*.

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.

Accordingly, 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, our standard cost assumption is currently $40 per tonne of CO_2e. 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.

Water

BP recognizes the importance of access to fresh water and the need to manage water discharges at our operations. We assess risks, such as water scarcity, wastewater disposal and the long-term social and environmental pressures on water resources within the local area.

We are investing in research with several universities in the US to help understand future risks in water management, such as the allocation and use of water in the Middle East and the impact of water policies and regulation around the world.

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 Algeria, Indonesia, Oman and the US.

Some stakeholders have raised concerns about the potential environmental and community impacts of hydraulic fracturing. BP seeks to apply responsible well design and construction, surface operation and fluid handling practices to mitigate these impacts.

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 the fracturing process help to reduce friction and control bacterial growth in the well. Some of these chemicals when used in certain concentrations are classified as hazardous by the relevant regulatory authorities, and each chemical used in the fracturing process is listed in the material safety data sheets kept at each operational site. We submit data on chemicals used at our hydraulically fractured wells in the US, to the extent allowed by our suppliers who own the chemical formulas, at *fracfocus.org*.

We aim to minimize air pollutant and greenhouse gas emissions by using responsible practices at our operating sites. For example, at our drilling sites in the US we use a process called green completions, whenever possible, to manage methane emissions associated with well completions following hydraulic fracturing. This process recovers natural gas for sale and minimizes the amount of natural gas either flared or vented from our wells.

Table of Contents

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Environmental monitoring at our Terre de Grace oil sands lease area in Northern Alberta, Canada.

We seek to design and locate our equipment and manage our work patterns in ways that reduce potential impacts to communities such as increased traffic, noise, dust and light. 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

Oil sands in Canada are the third-largest proven crude oil reserves in the world, after Saudi Arabia and Venezuela. About half of the world s total oil reserves that are open to private sector investment are contained in Canada s oil sands. BP is involved in three oil sands lease areas, all of which are located in the province of Alberta. We expect the Sunrise Energy Project, operated by Husky Energy, to be the first onstream with production expected to begin in late 2014. Engineering and appraisal activities are under way to design and plan the construction of the first phase of Pike, which is operated by Devon Energy. Terre de Grace, which is BP-operated, is currently under appraisal for development.

Our decision to invest in Canadian oil sands projects takes into consideration GHG emissions, impacts on land, water use, local communities and commercial viability. In the case of joint arrangements in which we are not the operator, we monitor both 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*.

Human rights

BP s human rights policy, published in 2013, outlines our commitment to respect internationally-recognized human rights, as set out in the International Bill of Human Rights and the International Labour Organization s Declaration on Fundamental Principles and Rights at Work. The policy applies to all employees and officers in BP wholly owned entities and in joint arrangements to the extent possible and reasonable given BP s level of participation.

The United Nations Guiding Principles on Business and Human Rights outline specific responsibilities for businesses in relation to human rights. We are committed to working towards aligning with the Guiding Principles using a risk-based approach. In 2013 our actions included:

- Human rights workshops for senior leaders in Indonesia and the Middle East, with plans to roll these out in other high-priority regions.

Inclusion of human rights in our impact assessment for the LNG expansion project in Tangguh, Indonesia.

Collaboration with industry peers on the development of good practice guidance for integrating human rights into environmental and social impact assessments.

Participation in the work of oil and gas industry organization IPIECA s taskforce on developing shared industry approaches to managing human rights risks in the supply chain.

We plan to monitor the effectiveness of these actions. More information about our approach to human rights may be found at *bp.com/humanrights*.

Business ethics

Bribery and corruption are significant 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, whether in the public or private sector. We operate a group-wide anti-bribery and corruption standard, which applies to all BP employees and contractor staff. The standard requires annual bribery and corruption risk assessments; risk-based 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. Our processes are designed to enable us to choose suppliers carefully on merit, avoiding conflicts of interest and inappropriate gifts and entertainment.

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 (Dodd-Frank) in the US.

Financial transparency

As a member of the Extractive Industries Transparency Initiative (EITI), we work with governments, non-governmental organizations and international agencies to improve transparency and disclosure of payments to governments. BP is supporting several countries that are working towards becoming EITI compliant.

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 EU for companies in the extractive industries. We are awaiting the publication of the revised rules of the Dodd-Frank legislation from the SEC and are preparing to comply with the disclosure requirements.

We are contributing to the consultation process initiated by the UK government in preparation for the adoption of the EU accounting directive into UK law.

Enterprise and community development

In a number of BP locations, we run programmes to help build the skills of businesses and to develop the local supply chain. For example, we have helped some local companies reach the standards needed to supply BP and other organizations through training and sharing of our standards in areas such as health and safety.

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.

In 2013, we contributed $78.8 million in social investment. More information about our social contribution can be found at *bp.com/society*.

Table of Contents

Employees

BP seeks employees who have the right skills for their roles and who understand and embody the values and expected behaviours that guide everything we do as a group.

BP headcount

Number of employees at 31 December[a]	US	Non-US	Total
2013			
Upstream	**9,300**	**15,400**	**24,700**
Downstream	**8,300**	**39,700**	**48,000**
Other businesses and corporate	**1,900**	**9,200**	**11,100**
Gulf Coast Restoration Organization	**100**		**100**
	19,600	**64,300**	**83,900**
2012			
Upstream	9,500	14,700	24,200
Downstream	11,900	39,900	51,800
Other businesses and corporate	1,900	8,400	10,300
Gulf Coast Restoration Organization	100		100
	23,400	63,000	86,400
2011			
Upstream	8,900	13,500	22,400
Downstream	12,000	39,500	51,500
Other businesses and corporate	1,900	8,200	10,100
Gulf Coast Restoration Organization	100		100
	22,900	61,200	84,100

[a] Reported to the nearest 100.

As at the end of December 2013, we had 83,900 employees. This includes 14,100 service station staff and 4,300 agricultural, operational and seasonal workers in Brazil. The numbers for 2011 and 2012 have been restated following the adoption of IFRS 11, see Financial statements Note 1 for further information.

During 2013, 4,300 people left BP through divestments, while there was an increase in seasonal workers in our biofuels business resulting in an overall headcount decrease of 3% from 2012.

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 are 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

We are focused on protecting 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.

The group people committee, chaired by the group chief executive, has overall responsibility for key policy decisions relating to employees. The committee is responsible for governance of BP s people management processes. The committee discussed longer-term people priorities, reward, progress in our diversity and inclusion programme, recruitment priorities (including graduate recruitment), and improvements to our learning and development programmes in 2013.

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. We want to develop the skills we need from within our existing workforce and we complement this with targeted external recruitment.

To address increasing demand for skilled people across the globe, 44% of our graduate recruitment came from universities outside the UK and US in 2013. 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 achieve 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 being considered.

Building enduring capability

We provide development opportunities for all our employees, including international assignments, mentoring, team development days, workshops, seminars and online learning.

We continue to work to embed appropriate leadership skills throughout our organization. By 2013 our group-wide suite of leadership development programmes had been attended by employees from 32 countries and were conducted in six different languages.

We provide leading education opportunities for our people through our internal academies and institutes that deliver leadership development, technical learning and compliance programmes.

Diversity

We are a global company and aim for a workforce that is representative of the societies in which we operate.

We have set out our ambitions for diversity and our group people committee reviews performance on a quarterly basis. We aim for 25% of our group leaders the most senior managers of our businesses and functions to be women by 2020.

Workforce by gender

Numbers as at 31 December	Male	Female	Female %

Board directors	12	2	14
Group leaders	477	105	18
Subsidiary directors	494	107	18
All employees	58,500	25,400	30

At the end of 2013, 22% of our group leaders came from countries other than the UK and the US. 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 support the UK government-commissioned Lord Davies review which recommends increasing gender diversity on the boards of listed companies. See page 70 for information on our board composition.

Inclusion

Our goal is to create an environment of inclusion and acceptance. For our employees to be 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.

Table of Contents

We aim to ensure equal opportunity in recruitment, career development, promotion, training and reward for all employees, including women; ethnic minorities and different nationalities; lesbian, gay, bisexual and transgender people; those with disabilities; and people of all ages. Where existing employees become disabled, our policy is to provide continuing employment and training wherever possible.

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. We seek to maintain constructive relationships with labour unions.

We conduct an annual engagement survey among our employees. In 2013 approximately 37,000 employees in more than 70 countries gave their views on a wide range of business topics and to identify areas where we can improve.

We measure how engaged our employees are with our strategic priorities. The group priorities index is derived from 12 questions about employee perceptions of BP as a company and how it is managed in terms of leadership and standards. We saw continued improvement in 2013 with a score of 72% (2012 71%, 2011 67%).

Business leadership teams review the results of the survey and agree actions to address identified issues. In 2013, safety scores remained strong and there was an increase in employees understanding of the operating management system, an area of focus identified in the previous year. While the survey showed an increase in employee confidence in BP s leadership, work is needed to further strengthen this.

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Global business services (GBS) supports BP s business processes across the globe. Here, members of the family day organizing committee in Malaysia prepare the registration booth.

Share ownership

We encourage employee share ownership. For example, through our ShareMatch plan, which operates in more than 50 countries, we match BP shares purchased by our employees. We operate a single company-wide equity plan, which allows employee participation at different levels globally and is linked to the company s performance.

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.

Employees, contractors or other third parties who have concerns that laws, regulations or the code of conduct may be breached, can get help through OpenTalk, a helpline operated by an independent company. The number of cases raised through OpenTalk in 2013 was 1,121 (2012 1,295, 2011 796). The increase in OpenTalk cases over the past few years is due, in part, to initiatives to promote our code of conduct and speak up culture. This is supported by high scores in our employee engagement survey relating to employee understanding of the importance of speaking up. The most common issues raised in 2013 related to the people section of the code. This includes treating people fairly, with dignity and giving everyone equal opportunity; creating a respectful, harassment-free workplace; and protecting privacy and confidentiality.

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 2013, 113 employee dismissals were reported by BP s businesses for non-adherence to the code of conduct or unethical behaviour. This excludes dismissals of staff employed at our retail service station sites, for incidents such as thefts of small amounts of money.

Following legal settlements with the US government in 2012, BP agreed to retain an ethics monitor for a term of up to four years from 2013. The ethics monitor will review and provide recommendations concerning BP s ethics and compliance programme (see page 39).

Policy on political activity

BP has a policy of not participating directly in party political activity as a group or making any contributions to political candidates, whether in cash or in kind. Employees rights to participate in political activity are governed by the applicable laws in the countries in which we operate. For example, in the US, BP supports the operation of the BP employee political action committee to facilitate employee involvement and to assess whether contributions comply with the law and are publicly disclosed.

Table of Contents

Our management of risk

BP manages, monitors and reports on the principal risks and uncertainties that can impact our ability to deliver our strategy of meeting the world s energy needs responsibly while creating long-term shareholder value; these risks are described in the Risk factors on page 51.

Our management systems, organizational structures, processes, standards, code of conduct and behaviours together form a system of internal control that governs how we conduct the business of BP and manage associated risks.

BP s risk management system

BP s risk management system is designed to be a simple, consistent and clear framework for managing and reporting risks from the group s operations to the board. The system seeks to avoid incidents and maximize business outcomes by allowing us to:

- Understand the risk environment, and assess the specific risks and potential exposure for BP.
- Determine how best to deal with these risks to manage overall potential exposure.
- Manage the identified risks in appropriate ways.
- Monitor and seek assurance of the effectiveness of the management of these risks and intervene for improvement where necessary.
- Report up the management chain to the board on a periodic basis about how risks are being managed, monitored, assured and the improvements that are being made.

Our risk management activities

Day-to-day risk management management and staff at our facilities, assets and functions identify and manage risk, promoting safe, compliant and reliable operations. For example, our group-wide operating management system (OMS) integrates BP requirements on health, safety, security, environment, social responsibility, operational reliability and related issues. These BP requirements, along with business needs and the applicable legal and regulatory requirements, underpin the practical plans developed to help reduce risk and deliver strong, sustainable performance.

Business and strategic risk management our businesses and functions integrate risk into key business processes such as strategy, planning, performance management, resource and capital allocation, and project appraisal. We do this by collating risk data, assessing risk management activities, making further improvements and planning new activities. By using a standardized risk management report, we aim for a consistent view of risks across BP.

Oversight and governance the board, executive and functional leadership provide oversight to identify and understand significant risks to BP. They also put in place systems of risk management, compliance and control to mitigate these risks. Executive committees set policy and oversee the management of group risks, and dedicated board committees review and monitor certain risks throughout the year.

BP s group risk team analyses the group s risk profile and maintains the group risk management system. Our group audit team provides independent assurance to the group chief executive and board, through its committees, over 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.

Risk governance and oversight

Key risk governance and oversight committees include the following:

Executive committees

g Executive team meeting for strategic and commercial risks.

g Group operations risk committee for health, safety, security, environment and operations integrity risks.

g Group financial risk committee for finance, treasury, trading and cyber risks.

g Group disclosure committee for financial reporting risks.

g Group people committee for employee risks.

g Resource commitment meeting for risks related to investment decisions.

g Group ethics and compliance committee for risks associated with legal and regulatory compliance and ethics.

Board and its committees

g BP board.

g Audit committee.

g Safety, ethics and environment assurance committee.

g Gulf of Mexico committee.

Board committees
For information on the board and its committees see page 71.

Our risk profile

The nature of our business operations is long term, resulting in many of our identified risks being enduring in nature. Nonetheless, risks can develop and evolve over time and their potential impact or likelihood may vary in response to internal and external events.

As part of BP s annual planning process, we review the principal risks and uncertainties to the group. We identify those as having a high priority for particular oversight by the board and its various committees in the coming year; the risks identified for particular review in 2014 are listed below. These may be updated throughout the year in response to changes in internal and external circumstances. The oversight and management of the other risks is undertaken in the normal course of business throughout the business and in executive and board committees.

Further details of the principal risks and uncertainties we face are set out in the Risk factors on page 51. There can be no guarantee that our risk management activities will mitigate or prevent these, or other, risks from occurring.

Gulf of Mexico oil spill

There is a wide range of risks arising out of the Gulf of Mexico accident and oil spill. These include legal, operational, reputational and compliance risks.

BP s management and mitigation of these risks is overseen by the board s Gulf of Mexico committee, which seeks to ensure that BP fulfils all legitimate obligations whilst protecting and defending BP s interests.

The committee s responsibilities include oversight and review of the following activities: the legal strategy for litigation; investigations and suspension and debarment actions arising from the accident and oil spill; the strategy connected with settlements and claims; the environmental work to remediate or mitigate the effects of the oil spill; management strategy and actions to restore the group s reputation in the US; and compliance with government settlement agreements arising out of the accident and oil spill.

See Legal proceedings page 257 and Gulf of Mexico committee page 78 for further information.

Strategic and commercial risks

10-point plan

In 2011 we set out a 10-point plan to address our priorities through 2014. Among other things, the plan aims to focus on safety and risk management, efficient investments and disposals, successful delivery of operating cashflows, renewal and repositioning of our portfolio, and delivery of our major projects to plan. We conduct regular planning and performance monitoring activity as part of managing the risks to delivery of this plan. For an update on our progress against the plan see page 22.

Geopolitical

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. Geopolitical risk is inherent to many regions in which we operate; heightened political or social tensions or changes in key relationships could adversely affect the group. We seek to manage this risk actively through the development and maintenance of relationships with governments and stakeholders in each country and region. In addition, we closely monitor events (such as the situation that arose in the Ukraine in February 2014) and implement risk mitigation plans where appropriate.

Cybersecurity

The threats to the security of our digital infrastructure continue to evolve and, like many other global organizations, our reliance on computers and network technology is increasing. A cybersecurity breach could have a significant impact on business operations. We seek to manage this risk through cybersecurity standards, ongoing monitoring of threats, close co-operation with authorities and awareness initiatives throughout the company. We also maintain disaster recovery, crisis and business continuity management plans.

Compliance and control risks

Ethical misconduct and legal or regulatory non-compliance

Ethical misconduct or breaches of applicable laws or regulations could damage our reputation, adversely affect operational results and shareholder value, and potentially affect our licence to operate. Our code of conduct and our values and behaviours, applicable to all employees, are central to managing this risk. Additionally, we have various group requirements covering areas such as anti-bribery and corruption, anti-money laundering, competition/anti-trust law and trade sanctions. We keep abreast of new regulations and legislation and plan our response to them. We also operate a range of compliance training and monitoring programmes for our employees. We offer an independent confidential helpline, OpenTalk, for employees, contractors and other third parties. For information on our code of conduct, see page 48.

Under the terms of the US Department of Justice settlement (see Legal proceedings on page 257), an ethics monitor will also review and provide recommendations concerning BP s ethics and compliance programme.

Trading non-compliance

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

Safety and operational risks

Process safety, personal safety and environmental risks

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 releases of hydrocarbons when drilling wells, operating facilities and transporting hydrocarbons. We apply our operating management system (OMS), including group and engineering technical practices as applicable, to address these risks. See page 41 for more information on safety and our OMS. Activities include inspection, maintenance, testing, business continuity and crisis response planning, and competency development for our employees and contractors. In addition, we conduct our drilling activity through a global wells organization in order to promote a consistent approach for designing, constructing and managing wells.

Security

Hostile acts such as terrorism or piracy could harm our people and disrupt our operations. We monitor for emerging threats and vulnerabilities to manage our physical and digital security. Physical security threats tend to vary geographically and by type of business. Our central security team provides guidance and support to a network of regional security advisers who advise and conduct assurance with respect to the management of security risks affecting our people and operations. We also maintain disaster recovery, crisis and business continuity management plans.

Table of Contents

Risk factors

We urge you to consider carefully the risks described below. The potential impact of the occurrence, or recurrence, 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, including the 10-point plan.

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

Gulf of Mexico oil spill

The spill has had and could continue to have a material adverse impact on BP.

There is significant uncertainty regarding the extent and timing of the remaining costs and liabilities relating to the 2010 Gulf of Mexico oil spill (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, fines and penalties that become payable by BP (including as a result of 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. These uncertainties are likely to continue for a significant period and may cause our costs to increase materially. 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. See, in particular, Access and renewal; Liquidity, financial capacity and financial, including credit, exposure; Insurance; US government settlements and debarment; Regulatory; Liabilities and provisions; Reporting; and Process safety, personal safety and environmental risks 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 and the effects of the Incident on our reputation and cash flows 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 affected 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, costs and liabilities relating to the Incident have placed, and will continue to place, a significant burden on our cash flow, which could impede our ability to invest in new opportunities and deliver long-term growth.

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 exchange rate fluctuations and 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), increased supply from the development of new oil and gas sources, technological change, global economic conditions and the influence 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. Decreases in oil, gas or product prices are likely to have an adverse effect on revenues, margins and profitability, and a material rapid change, or a sustained change, in oil, gas or product prices may mean investment or other decisions need to be reviewed, assets may be impaired, and the viability of projects may be affected. 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.

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.

Periods of global recession or prolonged instability in financial markets could negatively impact parties with whom we do or may do business, the demand for our products and the prices at which they can be sold and could affect the viability of the markets in which we operate.

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, potential restrictions on the commercial viability of, or our ability to progress, upstream resources and reserves, and impacts on revenue generation and strategic growth opportunities. In addition, the changed nature of our participation in alternative energies could carry reputational, economic and technology risks.

Geopolitical 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 and regions 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 terrorism, 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. See page 4 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

Table of Contents

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 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 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 arrangements or associates and through contracting and sub-contracting arrangements. These arrangements often involve complex risk allocation, decision-making processes and indemnification arrangements, and BP has less control of such activities than we would have if BP had full ownership and 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 arrangement s or associate s best interests, or approve such matters without our consent. Additionally, our joint arrangement 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, then safety, the performance of the project and BP s costs may be adversely affected. Our joint arrangement 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 arrangement 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 or contractual arrangement. Should a key sub-contractor, such as a lessor of drilling rigs, no longer be 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 investment any future erosion of our relationship with Rosneft could adversely impact our business, strategic objectives, the level of our reserves and our reputation.

On 21 March 2013, we completed the sale of our 50% interest in TNK-BP to Rosneft and the purchase of additional shares in Rosneft. We now own a total shareholding in Rosneft of 19.75%. To the extent we fail to maintain a good commercial relationship with Rosneft in the future, or to the extent that as a non-controlling shareholder in Rosneft we are unable in the future to exercise significant 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 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 group strategy, investment selection and/or subsequent execution could lead to loss of opportunity, 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, regulatory or other reasons, 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 major projects over the plan period. Poor delivery of or operational challenges at 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 and our operating cash flows.

Digital infrastructure a breach of our digital security or a failure of our digital infrastructure 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 or failure of our digital infrastructure, due to intentional actions such as cyber-attacks, negligence or otherwise, could cause serious damage to business operations and, in some circumstances, could result in the loss of data or sensitive information, injury to people, loss of control of or damage to assets, harm to the environment, reputational damage, breaches of regulations, litigation, legal liabilities and reparation costs.

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

Crisis management and contingency plans are required to respond to, and to continue or recover operations following, a disruption or an incident. 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. 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.

Table of Contents

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 and retain 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.

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.

The group seeks to maintain a financial framework to ensure that it is able to maintain an appropriate level of liquidity and financial capacity, and commercial credit risk is measured and controlled to determine the group s total credit risk. Failure to accurately forecast, manage or maintain sufficient liquidity and credit to meet our needs (including a failure to understand and respond to potential liabilities) could impact our ability to operate and result in a financial loss. Trade and other receivables, including overdue receivables, may not be recovered whether an impairment provision has been recognized or not. Inability to determine adequately our credit exposure could lead to financial loss. Furthermore, a substantial and unexpected cash call or funding request could disrupt our financial framework or overwhelm our capacity to meet our obligations.

External events could materially impact the effectiveness of the group s financial framework. A credit crisis or significant economic shock 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.

In addition, a significant operational incident could result in decreases in our credit ratings which, together with the assessments published by analysts, the reputational consequences of any such incident and concerns about the group s costs arising from any such incident, ongoing contingencies, liquidity, financial performance and credit spreads, could increase the group s financing costs and limit the group s access to financing. The group s ability to engage in both its trading activities and non-trading businesses could also be impacted in such circumstances due to counterparty concerns about the group s financial and business risk profile and resulting collateral demands, which could be significant. 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. Any 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. If such constraints occur at a time when cash flows from our business operations are constrained, such as following a significant operational incident, 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

Incident.

See Financial statements Note 19 for more information on financial instruments and financial risk factors.

Insurance The limited capacity of the insurance market and BP s insurance strategy could, from time to time, expose the group 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 may 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 Incident.

Compliance and control risks

US government settlements and debarment our settlement with the US Department of Justice and the SEC in respect of certain charges related to the Incident 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. For a description of the terms of the DoJ and SEC settlements, see Legal proceedings on page 264. Under the DoJ settlement, BP has agreed to retain an independent third-party auditor who will review and report to the probation officer, the DoJ, and BP regarding BP Exploration & Production s (BPXP) compliance with the key terms of the settlement including the completion of safety and environmental management systems audits, operational oversight enhancements, oil spill response training and drills and the implementation of best practices. The DoJ settlement also provides for the appointment of an ethics monitor and a process safety monitor. See Gulf of Mexico oil spill on page 39. 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.

The US Environmental Protection Agency (EPA) has temporarily suspended a number of BP entities from participating in new federal contracts and subjected BPXP to mandatory debarment at its Houston headquarters. In addition, the EPA has initiated administrative proceedings to convert the temporary suspension of these BP entities into discretionary debarment. On 26 November 2013, the EPA issued a Notice of Continued Suspensions and Proposed Debarments that continued the suspensions of the previously suspended BP entities, suspended two new BP entities (BP Alternative Energy and BP Pipelines (Alaska) Inc.), and proposed discretionary debarment of all suspended BP entities. Both temporary suspension and mandatory debarment prevent a company from entering into new contracts or new leases with the US government that would be performed at the facility where a Clean Water Act violation occurred. See Legal proceedings on page 264. BP has a significant amount of operations in the US. See Upstream on page 25 and Oil and gas disclosures for the group on page 245. Prolonged suspension or debarment from entering new federal contracts, or further suspension or debarment proceedings in the future 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 in the future. In particular, prolonged suspension or debarment could prevent BP from accessing and developing material new oil and gas resources located in the US, or prevent BP from engaging in certain development arrangements with third parties that are standard in the oil and gas industry, which could make the development of certain of BP s existing reserves located in the US less commercially attractive than if relevant BP entities were not suspended or debarred.

Table of Contents

As a result of the SEC settlement, as of 5 February 2013 and for a period of three years thereafter, we are no longer 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 SEC settlement date of 10 December 2012 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. We also 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, affect the adequacy of our provisions and limit our access to new exploration properties.

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. 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. We remain exposed to changes in the regulatory and legislative 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, the imposition of trade or other sanctions, government actions to cancel or renegotiate contracts or other factors. 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 and we remain exposed to increases in amounts payable to governments or government agencies. 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 curtail or cease certain operations, 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.

Due to the Incident and remedial provisions contained in or that may result from the DoJ and SEC settlements and other past events in the US, it is likely that there will be additional oversight and 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. BP may be subjected to a higher number of citations and/or level of fines imposed in relation to any alleged breaches of safety or environmental regulations. 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, require changes to our drilling operations, exploration, development and decommissioning plans, 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.

We buy, sell and trade oil and gas products in certain regulated commodity markets. Failure to respond to changes in or to comply with trading regulations could result in regulatory action and damage to our reputation.

See page 254 for more information on environmental regulation.

Ethical misconduct and non-compliance ethical misconduct or breaches of applicable laws by our businesses or our employees could be damaging to our reputation and shareholder value.

Incidents of ethical misconduct, non-compliance with the recommendations of the ethics monitor appointed under the terms of the DoJ settlement or non-compliance with applicable laws and regulations, including anti-bribery, anti-corruption and anti-manipulation laws and trade or other sanctions, could be damaging to our reputation and shareholder value and could subject us to litigation and regulatory action or penalties under the terms of the DoJ settlement or otherwise. Multiple events of non-compliance could call into question the integrity of our operations. For example, in our trading functions, 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 page 257. For further information on the risks involved in BP s trading activities, see Treasury and trading activities below.

Liabilities and provisions BP s potential liabilities resulting from pending and future claims, lawsuits, settlements and enforcement actions relating to the Incident, together with the potential cost and burdens of implementing remedies sought in the various proceedings, 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 Incident 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, and additional lawsuits or private claims arising out of the Incident may be brought in the future.

While significant charges have been recognized in the income statement since the Incident occurred in 2010, the provisions recognized represent only the current best estimates of expenditures required to settle certain present obligations that can be reasonably estimated at the end of the reporting period, and there are future expenditures for which it is not possible to measure our obligations reliably. BP s total potential liabilities resulting from pending and future claims, lawsuits, settlements and enforcement actions relating to the Incident (including as a result of any potential determination of BP s negligence or gross negligence), together with the potential cost and burdens of implementing remedies sought in the various proceedings, cannot be fully estimated at this time and are subject to significant uncertainty but they have had, and are expected to continue to have, a material adverse impact on the group s business.

See Financial statements Note 2 and Legal proceedings on page 257.

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.

Table of Contents

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. See Legal proceedings on page 257.

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 arrangement partners and associates. See Strategic and commercial risks Joint and other contractual arrangements above.

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 hazardous, remote 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) addresses health, safety, security, environmental and operations risks, and aims 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.

Under the terms of the DoJ settlement (see Legal proceedings on page 264), a process safety monitor will review, evaluate, and provide recommendations concerning BPXP s process safety and risk management procedures for deepwater drilling in the Gulf of Mexico. Incidents of non-compliance with the recommendations of the process safety monitor 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.

Security hostile acts 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 facilities, 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.

Table of Contents

Liquidity and capital resources

Since the Gulf of Mexico oil spill in 2010 and the significant costs relating to the response activities and the 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 strengthen underpinned by a prudent financial framework.

The group s long-term credit ratings are A (positive outlook) from Standard & Poor s, and A2 (stable outlook) from Moody s Investor Services, both remaining unchanged during 2013.

We increased our financial flexibility in 2013 with the completion of the sale of BP s 50% share in TNK-BP to Rosneft in return for cash and shares. We received net $11.8 billion cash on completion (in addition to $0.7 billion already received as a dividend in December 2012), as well as increasing our shareholding in Rosneft from 1.25% to 19.75%.

Financial framework

We continue to refine our 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 flow[c]. We expect that the improvement in operating cash flow will be delivered partly from the completion of the Deepwater Horizon Oil Spill Trust fund payments, and partly through high-margin projects coming onstream. Any growth in operating cash flow will be available to increase both organic capital expenditure 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. We expect to continue to maintain a significant liquidity buffer while uncertainties remain.

Dividends and other distributions to shareholders

We are committed to maintaining a progressive and sustainable dividend policy through our focus on increasing sustainable free cash flows.

Since resuming dividend payments in 2011, we have steadily increased the dividend. From the quarterly dividend of 7 cents per share paid in 2011 it has increased by 36% to 9.5 cents per share paid in the fourth quarter of 2013. Going forward, the board will review the dividend level with the first and third quarter results each year.

The total dividend paid in cash to BP shareholders in 2013 was $5.4 billion with shareholders also having the option to receive a scrip dividend (2012 $5.3 billion cash). The dividend is determined in US dollars, the economic currency of BP.

During 2013 we started to buy back shares as part of an $8-billion share repurchase programme, fulfilling a commitment to offset any dilution to earnings per share from the Rosneft transaction. The total cash paid for share buybacks in 2013 was $5.5 billion (2012 nil). Details of share repurchases to satisfy the requirements of certain employee share-based payment plans are set out on page 278.

a

Operating cash flow is net cash provided by operating activities, as presented in the group cash flow statement on page 125.

[b] Assuming an oil price of $100 per barrel and a Henry Hub gas price of $5/mmBtu in 2014. The projection assumes BP s estimate of a Rosneft dividend. 2011 excludes BP s share of TNK-BP dividends. 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 2 for further information.

[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 125.

[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 28 for information on gross debt, which is the nearest equivalent measure to net debt on an IFRS basis.

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 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 regarding its borrowings. Also see Risk factors on page 51 for further information on risks associated with prices and markets and Financial statements Note 19.

The group s finance debt at 31 December 2013 amounted to $48.2 billion (2012 $48.8 billion). Of the total finance debt, $7.4 billion is classified as short term at the end of 2013 (2012 $10.0 billion). The short-term balance includes $6.2 billion for amounts repayable within the next 12 months relating to long-term borrowings (2012 $6.2 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 2013, outstanding commercial paper amounted to $1.0 billion (2012 $3.0 billion). We have a European Debt Issuance Programme (DIP) in place under which the group may raise up to $30 billion of debt for maturities of one month or longer. At 31 December 2013, the amount drawn down against the DIP was $13.9 billion (2012 $14.0 billion). Since 5 February 2013 the group has had a US shelf registration statement with a limit of $30 billion. This was converted from an unlimited shelf registration following the approval in December 2012 of the SEC settlement in respect of Deepwater Horizon-related claims. At 31 December 2013 $6.9 billion had been drawn down since conversion. In addition, the group has an Australian Note Issuance Programme of $5 billion Australian dollars, and as at 31 December 2013 the amount drawn down was $0.8 billion Australian dollars (2012 A$0.5 billion).

None of the capital market bond issuances since the Gulf of Mexico oil spill contain any additional financial covenants compared with the group s capital markets issuances prior to the incident.

BP accessed international capital markets throughout the year using its US, European and Australian issuance programmes, with bond issuances amounting to $8.6 billion in 2013.

The maturity profile and fixed/floating rate characteristics of the group s debt are described in Financial statements Note 19.

Net debt was $25.2 billion at the end of 2013, a reduction of $2.3 billion from the 2012 year-end position of $27.5 billion. The ratio of net debt to net debt plus equity was 16.2% at the end of 2013 (2012 18.7%). Net debt 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 28 for gross debt, which is the nearest equivalent measure on an

IFRS basis, and for further information on net debt.

Cash and cash equivalents of $22.5 billion at 31 December 2013 (2012 $19.6 billion) are included in net debt. We manage our cash position to ensure the group has adequate cover to respond to potential short-term market illiquidity, and expect 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 or invested in high grade commercial paper 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 19, and on the cash position in Financial statements Note 23.

Table of Contents

The group also has access to significant sources of liquidity in the form of committed bank facilities. We renegotiated our committed bank facilities during 2013, putting in place borrowing facilities of $7.4 billion (2012 $6.8 billion) with 26 international banking counterparties, of which $7.0 billion is available to draw and repay over a term of five years and $0.4 billion is available to draw and repay over a term of three years. In addition, the group continued to strengthen its access to commercial bank letters of credit (LC) and at the end of 2013 had in place committed LC facilities of $7.5 billion and secured LC arrangements of $2.4 billion, to supplement its uncommitted and unsecured LC lines.

We believe that the group has sufficient working capital for foreseeable requirements, taking into account the amounts of undrawn borrowing facilities and increased levels of cash and cash equivalents, and the ongoing ability to generate cash.

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 page 51 and Financial statements Note 2 for further information.

Off-balance sheet arrangements

At 31 December 2013, the group s share of third-party finance debt of equity-accounted entities was $17,008 million (2012 $6,884 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 2013 were $199 million (2012 $237 million) in respect of liabilities of joint ventures and associates and $648 million (2012 $713 million) in respect of liabilities of other third parties. Of these amounts, $115 million (2012 $166 million) of the joint ventures and associates guarantees relate to borrowings and for other third-party guarantees, $487 million (2012 $543 million) relates to guarantees of borrowings. Details of operating lease commitments, which are not recognized on the balance sheet, are shown in the table on page 252 and provided in Financial statements Note 9.

Contractual obligations

The following table summarizes the group s contractual obligations, capital expenditure commitments for property, plant and equipment at 31 December 2013 and the proportion of that expenditure for which contracts have been placed.

			$ million
		Capital expenditure	
Expected payments by period	Contractual obligations[a]	Committed	of which is contracted
2014	134,075	17,973	8,676
2015	40,471	9,010	2,581
2016	29,279	5,703	1,321
2017	23,186	4,021	685
2018	20,360	2,292	189
2019 and thereafter	105,377	3,443	253
Total	352,748	42,442	13,705

[a] Including $100,805 million for which a liability is recognized on the balance sheet.
The group s principal contractual obligations and a description of the nature of the group s unconditional purchase obligations are provided on page 252.

Capital expenditure is considered to be committed when the project has received the appropriate level of internal management approval. For joint operations, the net BP share is included in the amounts above.

In addition, at 31 December 2013, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $1,458 million. Contracts were in place for $161 million of this total.

Cash flow

The following table summarizes the group s cash flows.

			$ million
	2013	2012	2011
Net cash provided by operating activities	**21,100**	20,479	22,218
Net cash used in investing activities	**(7,855)**	(13,075)	(26,753)
Net cash provided by (used in) financing activities	**(10,400)**	(2,010)	477
Currency translation differences relating to cash and cash equivalents	**40**	64	(493)
Increase (decrease) in cash and cash equivalents	**2,885**	5,458	(4,551)
Cash and cash equivalents at beginning of year	**19,635**	14,177	18,728
Cash and cash equivalents at end of year	**22,520**	19,635	14,177

Net cash provided by operating activities for the year ended 31 December 2013 was $21,100 million compared with $20,479 million for 2012. The cash outflow in respect of the Gulf of Mexico oil spill reduced from $2,382 million in 2012 to $73 million in 2013. Excluding the impacts of the Gulf of Mexico oil spill, net cash provided by operating activities was $21,173 million for 2013, compared with $22,861 million for 2012, a decrease of $1,688 million. Profit before taxation excluding the impact of the Gulf of Mexico oil spill increased by $7,545 million, of which $9,163 million related to the non-cash impacts of higher depreciation, impairments and gains and losses on disposal offset by lower earnings from joint ventures and associates. An increase in working capital requirements of $3,920 million was largely offset by lower income taxes paid.

Net cash provided by operating activities for the year ended 31 December 2012 was $20,479 million compared with $22,218 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 $22,861 million for 2012, compared with $29,031 million for 2011, a decrease of $6,170 million. Profit before taxation excluding the impacts of the Gulf of Mexico oil spill decreased by $11,341 million, of which $4,730 million related to the non-cash impacts of higher depreciation, impairments and gains and losses on disposal and lower equity-accounted earnings of joint ventures and associates. A reduction in working capital requirements of $3,667 million was largely offset by lower dividends received from joint ventures and associates, principally TNK-BP.

Net cash used in investing activities was $7,855 million in 2013 (2012 $13,075 million and 2011 $26,753 million). The decrease in cash used in 2013 reflected an increase in disposal proceeds of $10,401 million, partly offset by an increase in our investments in equity-accounted entities, mainly relating to the completion of the sale of our interest in TNK-BP and subsequent investment in Rosneft. There was also an increase in our other capital expenditure excluding acquisitions of $1,298 million. 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 $8,757 million. This was partially offset by an increase in capital expenditure excluding acquisitions of $5,914 million.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $30 billion in 2013 (2012 $24.8 billion and 2011 $18.9 billion). Sources of funding are fungible, but the majority of the group s funding requirements for new investment come from cash generated by existing operations.

Net cash used in financing activities was $10,400 million in 2013 (2012 $2,010 million and 2011 $477 million net cash provided by financing activities). The increase in net cash used in 2013 primarily reflected the buyback of shares of $5.5 billion as part of our $8-billion share repurchase programme, lower net proceeds of $1,055 million from long-term financing and an increase in the net repayment of short-term debt of $1,353 million. The increase in net cash used in 2012 primarily reflected a net decrease in short-term debt of $2,888 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.

During the period 2011 to 2013, our total sources of cash amounted to $101 billion, and our total uses of cash amounted to $106 billion. The increase in cash and cash equivalents held of $4 billion was financed by an increase in finance debt of $9 billion over the three-year period. During this period, the price of Brent crude oil has averaged $110.53 per barrel. Sources and uses of cash over the three-year period as a whole, are analysed in the table below.

	$ billion
Sources of cash:	
Net cash provided by operating activities	64
Disposals	37
	101
Uses of cash:	
Capital expenditure	74
Acquisitions	11
Net repurchase of shares	5
Dividends paid to BP shareholders	15
Dividends paid to non-controlling interests	1
	106
Net use of cash	(5)
Increase in finance debt	9
Increase in cash and cash equivalents	4

Disposal proceeds received in cash during the three-year period exceeded cash used for acquisitions, as a result in particular of our ongoing disposal programme started in 2010 and the disposal of our interest in TNK-BP in 2013. Net investment (capital expenditure and acquisitions less disposal proceeds) during this period averaged $16 billion per year. Dividends paid to BP shareholders totalled $15 billion during the three-year period. 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.

Acquisitions and disposals

There were no significant acquisitions in 2013 and 2012.

In 2011, we acquired a 30% interest in each of 21 oil and gas production-sharing agreements operated by Reliance Industries Limited in India for $7.0 billion. We also 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.

During 2013 BP completed 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. For more information on this transaction see Financial statements Note 6.

Total cash disposal proceeds received during 2013 were $22 billion. This included $16.7 billion for the disposal of BP s interest in TNK-BP, $1.4 billion for the disposal of our Texas City refinery and a portion of its retail and logistics network in the south-eastern US to Marathon Petroleum Corporation and $2.2 billion for the sale of the Carson refinery in California, and related assets in the region to Tesoro Corporation. We also completed the sale of our interests in a number of central North Sea oil and gas fields to TAQA.

Total disposal proceeds received during 2012 were $11.6 billion. This 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, $1.5 billion for the sale of the Canadian natural gas liquids (NGL) business to Plains Midstream Canada ULC and $1.025 billion for the sale of BP s interest in the Jonah and Pinedale upstream operations in Wyoming, to LINN Energy, LLC.

Total disposal proceeds received during 2011, after the repayment of the disposal deposit relating to Pan American Energy LLC (PAE), were $2.8 billion.

See Financial statements Note 3 and Note 4 for further details of business combinations and non-current assets held for sale.

The Strategic report was approved by the board and signed on its behalf by David J Jackson, Company Secretary on 6 March 2014.

Table of Contents

Table of Contents

Board of directors[a]

As at 6 March 2014

Key to portraits

1 Carl-Henric Svanberg	2 Bob Dudley	3 Paul Anderson	4 Admiral Frank Bowman
5 Antony Burgmans	6 Cynthia Carroll	7 Iain Conn	8 George David
9 Ian Davis	10 Professor Dame Ann Dowling	11 Dr Brian Gilvary	12 Brendan Nelson
13 Phuthuma Nhleko	14 Andrew Shilston		

[a] The ages of the board are correct as at 31 December 2013.

Table of Contents

Carl-Henric Svanberg

Chairman

Tenure

Appointed to the board 1 September 2009 (4 years)

Board and committee activities

Chairman

Chairman of the chairman s committee

Chairman of the nomination committee

Attends the safety, ethics and environment assurance committee (SEEAC)

Attends the Gulf of Mexico committee

Attends the remuneration committee

Outside interests

Chairman of AB Volvo

Age

61

Nationality

Swedish

Career

Carl-Henric Svanberg became chairman of the BP board on 1 January 2010.

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, a member of the Advisory Board of Harvard Kennedy School and on the Leadership Council of the United Nations Sustainable Development Solutions Network. He is also the recipient of the King of Sweden s medal for his contribution to Swedish industry.

Relevant experience and skills

Carl-Henric Svanberg s career in global business, latterly as chief executive officer of Ericsson, is particularly relevant to BP as has been demonstrated during his tenure as chairman. In leading the board, he has focused on the development of the group s strategy and its communication to shareholders. He has also concentrated on the work of the nomination committee in endeavouring to ensure that the board has a strong list of candidates to secure its stewardship of the company.

Carl-Henric Svanberg s performance during the year has been evaluated by the chairman s committee, led by Antony Burgmans.

Bob Dudley

Group chief executive

Tenure

Appointed to the board 6 April 2009 (4 years)

Outside interests

Non-executive director of Rosneft

Member of Tsinghua Management University Advisory Board, Beijing, China

Member of BritishAmerican Business International Advisory Board

Member of UAE/UK CEO Forum

Member of Turkish/British CEO Forum

Member of Russian Geographical Society

Age

58

Nationality

American

Career

Bob Dudley became group chief executive on 1 October 2010.

Bob 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 in Moscow. 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 was appointed a director of Rosneft in March 2013 following BP s acquisition of a stake in Rosneft.

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 has given him substantial global experience.

Since his appointment as group chief executive in 2010, Bob has re-organized the operations of the group and has moved its focus to value not volume; all without any compromise on safety. During the year he has successfully completed the disposal of the group s interest in TNK-BP and the acquisition of a significant stake in Rosneft.

Bob Dudley s performance has been considered and evaluated by the chairman s committee.

Table of Contents

Paul Anderson

Independent non-executive director

Tenure

Appointed 1 February 2010 (4 years)

Board and committee activities

Chairman of the SEEAC

Member of the chairman s committee

Member of the nomination committee

Member of the Gulf of Mexico committee

Outside interests

Non-executive director of BAE Systems PLC.

Age

68

Nationality

American

Career

Paul Anderson 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. He also 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 became a board member in early 2010, joining the SEEAC. He was a member of the Gulf of Mexico committee from its formation in August 2010. He took the chair of the SEEAC in December 2012. As chair he has continued the committee s focus on safety matters. His broad experience of the global oil and gas industry and of the US business environment has benefited 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.

He has led the SEEAC on several visits to the company s operations and has commenced a dialogue with the company s socially responsible investors.

Admiral Frank Bowman

Independent non-executive director

Tenure

Appointed 8 November 2010 (3 years)

Board and committee activities

Member of the SEEAC

Member of the chairman s committee

Member of the Gulf of Mexico committee

Outside interests

President of Strategic Decisions, LLC.

Director of Morgan Stanley Mutual Funds

Director of the American Shipbuilding Suppliers Association

Director of Naval and Nuclear Technologies, LLP.

Age

69

Nationality

American

Career

Frank Bowman 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 a director of the naval nuclear propulsion programme in the Department of the Navy and the Department of Energy for over eight years. He also completed two masters degrees in engineering at the Massachusetts Institute of Technology in 1973.

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 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 process 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, which has been important for his work on the SEEAC. He has made a significant contribution to the work of the Gulf of Mexico committee.

Antony Burgmans

Independent non-executive director

Tenure

Appointed 5 February 2004 (10 years)

Board and committee activities

Chairman of the remuneration committee

Member of the SEEAC

Member of the chairman s committee

Member of nomination committee

Outside interests

Member of the supervisory boards of Akzo Nobel N.V., AEGON N.V. and SHV Holdings N.V.

Chairman of the supervisory board of TNT Express

Age

66

Nationality

Dutch

Career

Antony Burgmans joined Unilever in 1972, holding a succession of marketing and sales posts, including the chairmanship of PT Unilever Indonesia from 1988 until 1991.

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. During his career he has lived and worked in London, Hamburg, Jakarta, Stockholm and Rotterdam.

Antony Burgmans has been nominated chairman of Akzo Nobel s supervisory board from April 2014.

Relevant experience and skills

Antony Burgmans executive career has been in the fields of 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 to his work on the SEEAC, on whose behalf he has made several visits to operations of the group.

He led the remuneration committee in its task of preparing a formal remuneration policy for adoption by shareholders. In this role he has had extensive dialogue with shareholders. He continues to provide wise counsel to the board and leads the evaluation of the chairman.

Table of Contents

Cynthia Carroll

Independent non-executive director

Tenure

Appointed 6 June 2007 (6 years)

Board and committee activities

Member of the SEEAC

Member of the chairman s committee

Member of nomination committee

Outside interests

Non-executive director of Hitachi Ltd.

Age

57

Nationality

American

Career

Early in her career in 1989, Cynthia Carroll joined Alcan (Aluminum Company of Canada) and ran a packaging company, led a global bauxite, alumina and speciality chemicals business and later was president and chief executive officer of the Primary Metal Group, responsible for operations in more than 20 countries. In 2007 she became the chief executive of Anglo American plc, the global mining group, operating in 45 countries with 150,000 employees, and was chairman of Anglo Platinum Limited and of De Beers s.a. She stepped down from these roles in April 2013.

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. She has been a leader in working to enhance safety performance in the mining industry, and her geo-political experience has been valuable during the course of the year, as has her work on the nomination committee.

She recently visited BP s operations in Alaska on behalf of the SEEAC.

Iain Conn

Chief executive, Downstream

Tenure

Appointed to the board 1 July 2004 (9 years)

Group responsibilities

Manufacturing, logistics, marketing operations of BP s fuels, petrochemicals and lubricants businesses

Group regional responsibility for Europe, southern Africa and Asia BP brand and related matters

Outside interests

Non-executive director and senior independent director of Rolls-Royce Holdings plc.

Chairman of the advisory board of Imperial College Business School

Member of the council of Imperial College

Age

51

Nationality

British

Career

Iain Conn was appointed chief executive, Downstream on 1 June 2007.

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, with responsibility for a number of group functions and regions.

Relevant experience and skills

Iain Conn s career has given him extensive knowledge of a broad range of BP s businesses, particularly in the Downstream, 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. He has continued to refocus the group s downstream operations whilst growing the contribution of that segment.

Iain Conn s performance has been evaluated by the group chief executive and considered by the chairman s committee.

George David

Independent non-executive director

Tenure

Appointed 11 February 2008 (6 years)

Board and committee activities

Member of the audit committee

Member of the remuneration committee

Member of the Gulf of Mexico committee

Member of the chairman s committee

Outside interests

Vice-Chairman of the Peterson Institute for International Economics

Age

71

Nationality

American

Career

George David began his career in 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 previously chaired BP s technology advisory council and has brought insights from that task to the board.

He is an active member of the audit, remuneration and Gulf of Mexico committees, bringing a strong US and global view to their deliberations.

Table of Contents

Ian Davis

Independent non-executive director

Tenure

Appointed 2 April 2010 (3 years)

Board and committee activities

Chairman of the Gulf of Mexico committee

Member of the remuneration committee

Member of the chairman s committee

Member of the nomination committee

Outside interests

Chairman of Rolls-Royce Holdings plc.

Non-executive member of the UK Cabinet Office

Non-executive director of Johnson & Johnson, Inc.

Senior adviser to Apax Partners LLP.

Age

62

Nationality

British

Career

Ian Davis 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 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 membership of the remuneration committee and chairmanship of the Gulf of Mexico committee.

As chairman of the Gulf of Mexico committee he has led the board s oversight of the response in the Gulf and guided their consideration of the various legal issues which continue to arise following the Deepwater Horizon accident.

Professor Dame Ann Dowling

Independent non-executive director

Tenure

Appointed 3 February 2012 (2 years)

Board and committee activities

Member of the SEEAC

Member of the remuneration committee

Member of the chairman s committee

Outside interests

Professor of Mechanical Engineering, head of the Department of Engineering and Deputy Vice-Chancellor at the University of Cambridge

Chair of the Physical Sciences, Engineering and Mathematics Panel in the Research Excellence Framework the UK Government s review of research in universities

Non-executive director of the Department for Business, Innovation & Skills (BIS)

Age

61

Nationality

British

Career

Dame Ann Dowling 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 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.

She has been nominated President of the Royal Academy of Engineering from September 2014.

Relevant experience and skills

Dame Ann Dowling has a strong academic and engineering background.

Having initially been a member of the SEEAC, she joined the remuneration committee in 2012. Her contributions on both of these committees are valued, as is her work with the BP technology advisory council, which she also joined during 2012 and which she now chairs.

Dr Brian Gilvary

Group chief financial officer

Tenure

Appointed to the board 1 January 2012 (2 years)

Group responsibilities

Finance, tax, planning, treasury, mergers and acquisitions, investor relations, audit, procurement and information technology activities Chairs the group financial risk committee

Outside interests

Visiting professor at Manchester University

Age

51

Nationality

British

Career

Dr Brian Gilvary was appointed chief financial officer on 1 January 2012.

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 in Europe and the United States, he became the downstream s chief financial officer and commercial director from 2002 to 2005.

He was a director of TNK-BP over two periods, from 2003 to 2005 and from 2010 until the sale of the business and acquisition of Rosneft equity in 2013. From 2005 until 2009 he was chief executive of the integrated supply and trading function, BP s commodity trading arm. In 2010 he was appointed deputy group chief financial officer with responsibility for the finance function.

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.

Brian has consistently worked to further strengthen the finance function. He has also developed the company s engagement with shareholders and continues to focus on financial efficiency.

Brian Gilvary s performance has been evaluated by the group chief executive and considered by the chairman s committee.

Table of Contents

Brendan Nelson

Independent non-executive director

Tenure

Appointed 8 November 2010 (3 years)

Board and committee activities

Chairman of the audit committee

Member of the nomination committee

Member of the chairman s committee

Outside interests

Non-executive director and chairman of the group audit committee of The Royal Bank of Scotland Group plc.

President of the Institute of Chartered Accountants of Scotland Member of the Financial Reporting Review Panel

Age

64

Nationality

British

Career

Brendan Nelson 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 and his role as the chair of the audit committee of a major bank. During the year he has led the audit committee in meeting the many challenges from increased changes to regulation.

Phuthuma Nhleko

Independent non-executive director

Tenure

Appointed 1 February 2011 (3 years)

Board and committee activities

Member of the audit committee

Member of the chairman s committee

Outside interests

Non-executive director of Anglo American plc

Non-executive director and chairman of MTN Group Ltd.

Age

53

Nationality

South African

Career

Phuthuma Nhleko 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 (formerly 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 particularly relevant to his work on the audit committee.

Andrew Shilston

Independent non-executive director

Tenure

Appointed 1 January 2012 (2 years)

Board and committee activities

Senior independent director

Member of the audit committee

Member of the chairman s committee

Attends the nomination committee

Outside interests

Non-executive director of Circle Holdings plc.

Chairman of Morgan Advanced Materials plc.

Age

58

Nationality

British

Career

Andrew Shilston 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.

His experience of the oil and gas industry has been important in assisting the board in their evaluation of projects and capital expenditure. As senior independent director he has attended meetings of the nomination committee.

Table of Contents

Executive team[a]

The executive team represents the principal executive leadership of the BP group. Its membership includes BP s executive directors (Bob Dudley, Iain Conn and Dr Brian Gilvary whose biographies appear on pages 61-64) and the senior management listed below.

As at 6 March 2014

Key to portraits

1	Rupert Bondy	2	Bob Fryar	3	Andy Hopwood	4	Katrina Landis
5	Bernard Looney	6	Lamar McKay	7	Dev Sanyal	8	Helmut Schuster

Rupert Bondy

Current position

Group general counsel

Executive team tenure

Appointed 1 May 2008 (5 years)

Outside interests

No external appointments

Age

52

Nationality

British

Career

Rupert Bondy is responsible for legal and compliance matters across the BP group.

Rupert began his career as a lawyer in private practice. In 1989 he joined US law firm Morrison & Foerster, working in San Francisco and London, 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, he was appointed senior vice president and general counsel of GlaxoSmithKline in 2001.

In April 2008 he joined the BP group, and he became the group general counsel on 1 May 2008.

[a] The ages of the executive team are correct as at 31 December 2013.

Bob Fryar

Current position

Executive vice president, safety and operational risk

Executive team tenure

Appointed 1 October 2010 (3 years)

Outside interests

No external appointments

Age

50

Nationality

American

Career

Bob Fryar 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 operational risk, with accountability for group-level disciplines including engineering, health, safety, security, and environment. In this capacity, he looks after the group-wide operating management system implementation and capability programmes.

Bob has 28 years experience in the oil and gas industry having joined Amoco Production Company in 1985. From October 2010 to February 2013 Bob was executive vice president of the 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 and regional integration of all exploration and production activities.

Prior to February 2013, Bob held several management positions in Trinidad, including chief operating officer for Atlantic LNG, and vice president of operations.

Prior to that, Bob served in a variety of engineering and management positions in onshore US and deepwater Gulf of Mexico including petroleum engineer, field manager, operations manager, resource manager, and asset manager. In addition, he worked on the Vastar integration team.

Table of Contents

Andy Hopwood

Current position

Chief operating officer, strategy and regions, Upstream

Executive team tenure

Appointed 1 November 2010 (3 years)

Outside interests

Chair of the BP Foundation

Age

55

Nationality

British

Career

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.

After joining BP in 1980 as a petroleum engineer, Andy 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, and the subsequent rationalization of BP s portfolio. 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, following the BP-Amoco merger, he was appointed business unit leader in Azerbaijan, before returning to London in 2001 as the Upstream chief of staff. He was then appointed business unit leader for BP s interests in Trinidad & Tobago until 2005, when 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 was appointed executive vice president, exploration and production.

Katrina Landis

Current position

Executive vice president, corporate business activities

Executive team tenure

Appointed 1 May 2013

Outside interests

Independent director of Alstom SA

Founding member of Alstom s Ethics, Compliance and Sustainability Committee

Member of Earth Day Network s Global Advisory Committee Ambassador to the U.S. Department of Energy s U.S. Clean Energy Education & Empowerment program

Age

54

Nationality

American

Career

Katrina Landis is responsible for BP s integrated supply and trading activities, Alternative Energy, shipping, technology and remediation management.

Katrina began her career with BP in 1992 in Anchorage, Alaska and held a variety of senior roles. She was chief executive officer of BP s integrated supply and trading Oil Americas from 2003 to 2006, group vice president of BP s integrated supply and trading from 2007 to 2008 and chief operating officer of BP Alternative Energy from 2008 to 2009. She was then appointed chief executive officer of BP Alternative Energy in 2009. On 1 May 2013, she became executive vice president, corporate business activities.

Bernard Looney

Current position

Chief operating officer, production

Executive team tenure

Appointed 1 November 2010 (3 years)

Outside interests

Member of the Stanford University Graduate School of Business Advisory Council

Fellow of the Energy Institute

Age

43

Nationality

Irish

Career

Bernard Looney is responsible for production operations, drilling, engineering, procurement and supply-chain management, as well as health, safety and environment in the upstream.

Bernard 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.

Table of Contents

Lamar McKay

Current position

Chief executive, Upstream

Executive team tenure

Appointed 16 June 2008 (5 years)

Outside interests

Member of Mississippi State University Dean s Advisory Council

Age

55

Nationality

American

Career

Lamar McKay is responsible for the combined Upstream business which consists of exploration, development and production.

Lamar 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 function. 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.

Dev Sanyal

Current position

Executive vice president, and group chief of staff

Executive team tenure

Appointed 1 January 2012 (2 years)

Outside interests

Non-executive director of Man Group plc

Member of the Accenture Global Energy Board

Member of the International Business Leaders Group of The Duke of Edinburgh s International Award Foundation

Trustee of the Career Academy Foundation

Age

48

Nationality

British and Indian

Career

Dev Sanyal is the accountable executive for all of BP s corporate activities in strategy and long-term planning, risk, economics, competitor intelligence, government and political affairs, policy and group integration and governance.

Dev 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.

Helmut Schuster

Current position

Executive vice president, group human resources director

Executive team tenure

Appointed 1 March 2011 (3 years)

Outside interests

No external appointments

Age

52

Nationality

Austrian

Career

Helmut Schuster became group human resources director on 1 March 2011. In this role he holds accountabilities for the BP human resources function.

Helmut 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.

Governance overview

Introduction from the chairman

I am pleased to describe the work of the BP board and its committees in 2013. This is the end of the fourth year in which I have had the privilege to chair the board of BP.

In this time I have been fortunate to work with a group of directors who, through the board and its committees, have made a significant contribution to the rebuilding of the company. While we have made good progress, we still have work to do.

In 2013, with some of the areas of uncertainty from 2012 behind us, we began to determine how the board would function in the future. Shareholders will see that the number of meetings of the board and the committees has appropriately decreased since 2012. We are moving to what we hope will be a more established rhythm. During the year, the nomination committee carried out a detailed review of current board skills and the needs of the board in terms of knowledge, expertise and diversity over the coming years. As part of this review directors were asked how the board should operate in future. In January, as part of the 2013 board evaluation, we reviewed this work in the context of the results of the evaluations over the past three years.

In looking at the past year I would like to highlight just some of the areas upon which we have focused. In 2011 the board agreed the 10-point plan, setting a clear strategy for the company and determined the measures by which that strategy should be evaluated. We want to be judged on the value we generate for our shareholders and not the volume of hydrocarbons that we produce. To do this we have to invest our capital wisely and be clear on how we will execute our projects so that value is maximized. All of this needs to be done without compromising on safety. So safety, strategy, project selection and project execution have been at the forefront of our discussions as a board.

I believe that we use our committees effectively to carry out the required oversight and governance of risk. The Gulf of Mexico committee has continued to work to cover the wide range of litigation in which we remain involved as a result of the Deepwater Horizon accident. This allows the board to focus on key areas of strategy. The SEEAC visited several operations to evaluate our safety culture and implementation of operational standards.

As a board we focus on the delivery of long-term value to our shareholders, but given the nature of our business we must do so in a way that is sensitive to the societies in which we work. This means setting values and standards of behaviour both inside and outside the company.

Fair, balanced and understandable

During the year, the board considered the changes to the UK Corporate Governance Code in the context of BP s governance practices. One of these changes has been the requirement for directors to make a statement that they consider the annual report and accounts, taken as a whole, to be fair, balanced and understandable.

As part of our considerations, we received an early draft of the annual report to enable time for review and comment. The audit committee and the SEEAC then met jointly to consider the criteria for a fair, balanced and understandable annual report and to review the processes underpinning the compilation and assurance of the report, in relation to financial and non-financial management information.

Following the joint meeting of the committees, the board then considered the annual report and accounts as a whole and discussed the tone, balance and language of the document, being mindful of new UK reporting requirements and consistency between the narrative sections and the financial statements. In evaluating whether the report is fair, balanced and understandable, the board reviewed the internal processes that form the group s reporting governance framework, including the role of the corporate reporting steering group, the use of content owners, and legal and auditor review.

It has been another challenging year, but one where the board has continued to work well and learn. I look forward to 2014.

Carl-Henric Svanberg

Chairman

Table of Contents

Board and committee attendance in 2013

	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	11	11									4[c]	4	6[c]	6
Paul Anderson[1]	11	11			7[c]	7			13	12	4	4	6	6
Frank Bowman	11	11			7	7			13	13			6	6
Antony Burgmans	11	11			7	7	6[c]	6			4	3	6	6
Cynthia Carroll[2]	11	11			7	7					4	4	6	5
George David[3]	11	11	12	12			6	6	13	12			6	5
Ian Davis[4]	11	11					6	5	13[c]	13	4	3	6	5
Ann Dowling	11	11			7	7	6	6					6	6
Brendan Nelson[5]	11	10	12[c]	12							4	4	6	6
Phuthuma Nhleko[6]	11	10	12	12									6	5
Andrew Shilston[7]	11	9	12	11									6	6
Executive directors														
Bob Dudley	11	11												
Iain Conn	11	11												
Brian Gilvary	11	11												
Byron Grote	5	5												

A = Total number of meetings the director was eligible to attend.

B = Total number of meetings the director did attend.

[C] Committee chairman.

*Includes a joint Audit Committee-SEEAC meeting to review BP s system of internal control and risk management.

[1] Paul Anderson was unable to attend the Gulf of Mexico committee meeting on 25 September 2013 due to a late change in the timing of the meeting.

[2] Cynthia Carroll was unable to attend the chairman s committee on 5 December 2013 due to personal commitments.

[3] George David was unable to attend the Gulf of Mexico committee meeting on 8 March 2013 due to a clash with travel arrangements; he was unable to attend the chairman s committee meeting on 24 July 2013 due to a late change in the timing of the meeting.

[4] Ian Davis was unable to attend the meetings of the nomination and remuneration committees on 24 July 2013 due to a conflicting board meeting.

[5] Brendan Nelson attended all scheduled board meetings in 2013, however he was unable to attend the board teleconference on 21 February 2013 that was called at short notice due to a prior commitment with the Royal Bank of Scotland plc.

[6] Phuthuma Nhleko was unable to attend the chairman s committee meeting on 24 July 2013 and the board meeting on 25 July 2013 due to unforeseen urgent family commitments.

[7] Andrew Shilston attended all scheduled board meetings in 2013, however he was unable to attend the two board teleconferences called at short notice on 16 January 2013 and 21 February 2013 due to prior commitments; he was unable to attend the audit committee meeting on 28 October 2013 due to major storms in the UK disrupting travel.

Board diversity

BP recognizes the importance of diversity, including gender diversity, at all levels of the company as well as the board. The company is committed to increasing diversity across our operations and has in place a wide range of activities to support the development and promotion of talented individuals, regardless of gender and ethnic background.

The board operates a diversity policy which aims to promote diversity in the composition of the board. Under this policy, director appointments are evaluated against the existing balance of skills, knowledge and experience on the board, with directors asked to be mindful of diversity, inclusiveness and meritocracy considerations when examining nominations to the board.

The implementation of this policy and the diversity mix of the board is monitored through agreed metrics. The board also considered diversity as part of the annual review of its performance and effectiveness.

The board is supportive of the recommendations contained in Lord Davies report *Women on Boards* for female board representation to increase to 15% by end 2013 and 25% by end 2015. Accordingly, the board set a goal to increase the number of female board members by two (to a total of three female directors) by the end of 2013. However, at the end of 2013 there were two female directors on the board (equating to 14%). The nomination committee has identified potential candidates with a diverse background and it is anticipated that an appointment is likely to be made in 2014.

Table of Contents

How the board works

Board governance in BP

The system of governance within which the BP board operates is set out in the BP board governance principles. These define the role of the board, its processes and its relationship with executive management. This system is reflected in the governance of the group s subsidiaries. The board governance principles can be found at *bp.com/governance*.

Role of the board

The board is responsible for the overall conduct of the group s business and the directors have duties under both UK company law and BP s articles of association.

The primary tasks of the board include:

g Active consideration and direction of long-term strategy, and approval of the annual plan.

g Monitoring of BP s performance against the strategy and plan.

g Obtaining assurance that the material risks to BP are identified and that systems of risk management and control are in place to mitigate such risk.

g Board and executive management succession.

Specific tasks are delegated to the board committees (see the reports of the committees on page 74). The board seeks to set the tone from the top for BP by working with management to agree the values of the company and considering specific issues, including health, safety, the environment and reputation.

Board composition

On 31 December 2013 the board had 14 directors the chairman, three executive directors and 10 independent, non-executive directors (NEDs).

The nomination committee keeps the balance and independence of the board under review (see the report of the nomination committee on page 79).

Key roles and responsibilities

The chairman

Carl-Henric Svanberg

- Provides leadership of the board.
- Acts as main point of contact between the board and management.
- Speaks on board matters to shareholders and other parties.
- Ensures that systems are in place to provide directors with accurate, timely and clear information to enable the board to operate effectively.
- Is responsible for the integrity and effectiveness of the BP board s system of governance.

The group chief executive

Bob Dudley

- Is responsible for day-to-day management of the group.
- Chairs the executive team (ET), the membership of which is set out on page 66.

The senior independent director

Andrew Shilston

- Is available to shareholders if they have concerns that cannot be addressed through normal channels.

Antony Burgmans, BP s 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 senior independent director is employed as an executive of the group. The nomination committee keeps succession plans for the chairman, senior independent director, group chief executive and senior management under review.

Appointment and time commitment

The chairman and NEDs have letters of appointment; there is no term limit on a director s service as BP proposes all directors for annual re-election by shareholders (a practice followed since 2004). While the chairman s appointment letter sets out the time commitment expected of him, the letters of appointment for NEDs do not set a fixed time commitment as it is anticipated that the time required of directors may fluctuate depending on demands of BP business and other events. It is expected that directors will allocate sufficient time to the company to perform their duties effectively.

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 annual report on remuneration (see page 106).

Independence and conflicts of interest

NEDs are expected to be independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of that judgement.

Antony Burgmans joined the board in February 2004 and by the time of the 2014 AGM will have served ten years as a director. In 2012, the board asked him to remain as a director until the 2016 AGM as it considered that his experience as the longest serving board member provides valuable insight, knowledge and continuity. The board has determined that he continues to meet the board s criteria for independence and will keep this under review.

The board is satisfied that there is no compromise to the independence of, and nothing to give rise to 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. The nomination committee keeps under review the other interests of the NEDs to ensure that the effectiveness of the board is not compromised.

Succession

Dr Byron Grote, an executive director, retired from the board at the AGM in 2013. There were no other changes to the board or committee membership during the year.

Table of Contents

Board activity

The board s activities are structured to enable the directors to fulfil their role, in particular with respect to strategy, monitoring, assurance and succession. The diagram below shows the main areas of focus by the board during 2013.

Board activities

Risk and assurance

During the year the board through its committees, regularly reviewed the processes whereby risks are identified, evaluated and managed. The effectiveness of the group s system of internal control and risk management were also assessed (see Internal Control Revised Guidance for Directors (Turnbull) on page 110).

The annual plan and the group strategy are central to BP s risk management programme. They provide a framework in which the board can consider significant risks, manage the group s overall risk exposure and underpin the delegation and assurance model for the board in its oversight of executive management and other activities. The board and its committees (principally audit, SEEAC and Gulf of Mexico committees) monitored the group risks which had been allocated following the board s review of the annual plan at the end of 2012.

Those group risks reviewed during 2013 included risks associated with the global economic climate, the delivery of BP s 10-point plan, the group s exposure to Russia and reputation management. The board considered at the half year whether any changes were required to the allocation of group risks and confirmed the schedule for oversight of these risks.

The group risks allocated for review by the board in 2014 include delivery of BP s 10-point plan and geopolitical risk associated with BP s operations around the world. The board s monitoring committees (audit, safety, ethics and environment assurance and Gulf of Mexico committees) were also allocated a number of group risks for review over the year: these are outlined in the reports of the committees on page 74. Further information on BP s system of risk management is outlined in Our management of risk on page 49.

International advisory board

BP s international advisory board (IAB) advises 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 when needed.

The IAB is chaired by BP s previous chairman, Peter Sutherland. Its membership in 2013 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 US budget deficit and BP s activities in Azerbaijan and North Africa.

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 also covers governance, duties of directors and the board committees that a director will join.

To help develop an understanding of BP s business, the board continues its learning through briefings and site visits. In 2013, the board received briefings on BP s code of conduct, the group s values and key business developments including legal updates, the economic outlook and the *BP Energy Outlook*. At its board meetings in Houston and India, the board met local management.

Non-executive directors are expected to attend at least one site visit per year. During 2013, the board made a number of visits, including to Canadian oil sands operations, India and the Gelsenkirchen refinery in Germany. Members of the SEEAC made site visits to BP s operations in Alaska and Tangguh. The chairman and Iain Conn, chief executive of BP s Downstream segment, visited the Whiting Refinery in the US. After each site visit, the board or appropriate committee is briefed on the impressions gained by the directors attending the visit.

Table of Contents

Board evaluation

Each year BP undertakes a 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 2013 the nomination committee undertook a review of board skills, activities and time commitment with a view to informing the succession profile of future board appointments. This was undertaken to ensure that the board was well positioned to challenge and develop BP s strategy. This review included a discussion on how the board should approach its work in future.

Given this review of board skills and the use of external facilitation in prior years, an internally designed board evaluation has been carried out for 2013 using an external facilitator (Lintstock), which tested key areas of the board s work, including strategy, assurance, risk and governance processes. The output of the review were discussed at the board and individually at each committee in January 2014.

Key conclusions from the evaluation

The evaluation concluded that progress had been made in improving the rhythm of board meetings and the timeliness of board paper distribution through the introduction of an online portal.

Good progress had been made during the year on the development of strategy and the governance around capital projects. Further work in both these areas was agreed for 2014. In addition, greater focus on technology and capability would be included as part of the board s considerations on strategy. The board also expressed a desire to look outwards when considering the rapidly evolving global energy market.

Follow up from our previous evaluation

After the 2012 evaluation, the board revised its agenda to increase the focus on strategic issues and introduced the regular use of forward agenda planning to enable this to be realized. The board also asked for greater interaction with the international advisory board, and a joint meeting has been scheduled for 2014. The number of board meetings reduced from 19 in 2012 to 11 in 2013, enabling the board to move back to a more steady state of operation.

Shareholder engagement

The company operates an active investor relations programme and the board receives feedback on shareholder views through results of an anonymous investor audit and reports from management and directors who interacted with shareholders over the year.

Institutional investors

Executive directors and senior management regularly meet with institutional investors through roadshows, group and one-to-one meetings and events for socially responsible investors.

During the year the chairman, senior independent director and chairs of the SEEAC and remuneration committee held investor meetings to discuss strategy, the board s view on the company s performance, governance and remuneration. An annual investor event was held in March 2013 with the chairman and chairs of the board committees. This meeting enables BP s largest shareholders to hear about the work of the board and its committees, and for non-executive directors to engage with investors.

Materials from investor presentations, including our financial results and information on the work of the board and its committees can be downloaded at *bp.com/investors*.

Private investors

Following a successful meeting in 2012, BP repeated an event for private investors in conjunction with the UK Shareholders Association (UKSA). A group of 50 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 gave shareholders the opportunity to ask questions on BP s activities and for the company to receive direct private shareholder feedback.

As part of the further development of BP s retail shareholder strategy, we commenced a lost shareholder programme in 2013 to trace and confirm shareholders contact details in order to successfully reunite them with their unclaimed dividends. Funds returned to shareholders as at 31 January 2014 amounted to £1,512,882.

AGM

The voting levels for the 2013 AGM saw an increase over the previous year to 64.2% (versus 63.2% in 2012). A webcast, speeches and presentations from the AGM are available on the BP website after the meeting, together with the outcome of voting on each resolution. Each year the board receives a report after the AGM giving a breakdown of the vote and investor feedback on their voting decisions for the meeting, informing the board on any issues arising.

UK Corporate Governance Code compliance

BP complied throughout 2013 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. This wider process enables all board members to 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 2012* 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 developments in the company s legal proceedings in the US.

Table of Contents

Committee reports

Audit committee

Chairman s introduction

The work of the audit committee in 2013 has been focused on three key themes. Firstly, financial reporting and accounting judgements, particularly with respect to assessing BP s financial responsibilities arising from the Deepwater Horizon accident. Secondly, reviews of key group-level risks and BP s system of controls and risk management. Thirdly, regular reports which assist the committee in maintaining assurance over the management of financial risk and in overseeing the performance of the external auditor. These have been supplemented by private meetings of the committee with key constituents, including our group audit function, the group ethics and compliance officer and lead external audit partners.

The monitoring committees of the audit, SEEA and Gulf of Mexico have continued to operate according to agreed areas of oversight that enable them to inform the wider board s view. As chair of the audit committee, I reported after each meeting to the board on the main matters discussed in our meeting to ensure all directors were informed of the committee s work. I believe the mix of skills and experience amongst the committee s members, together with the ability to discuss issues directly with management has led to an effective performance from the committee over the year.

Brendan Nelson

Committee chair

Role of the committee

The committee monitors the effectiveness of the group s financial reporting and systems of internal control and risk management.

Key responsibilities

- Monitoring and obtaining assurance that the management or mitigation of financial risks are appropriately addressed by the group chief executive and that the internal control system is designed and implemented effectively in support of the limits imposed by the board (Executive Limitations) as set out in the BP board governance principles;

- Reviewing financial statements and other financial disclosures and monitoring compliance with relevant legal and listing requirements;

Reviewing the effectiveness of the group audit function and BP s internal financial controls and systems of internal control and risk management;

Overseeing the appointment, remuneration, independence and performance of the external auditor and the integrity of the audit process as a whole, including the engagement of the external auditor to supply non-audit services to BP;

Reviewing the systems in place to enable those who work for BP to raise concerns about possible improprieties in financial reporting or other issues and for those matters to be investigated.

Members

Name	Membership status
Brendan Nelson (chairman)	Member since November 2010; chairman since April 2011
George David	Member since February 2008
Phuthuma Nhleko	Member since February 2011
Andrew Shilston	Member since February 2012

Brendan Nelson is chair of the audit committee. He was formerly vice chairman of KPMG, is chairman of the group audit committee of The Royal Bank of Scotland Group plc, a member of the Financial Reporting Review Panel and president of the Institute of Chartered Accountants of Scotland. The board is satisfied that Mr 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 Mr Nelson may be regarded as an audit committee financial expert as defined in Item 16A of Form 20-F.

Meetings are also attended by the chief financial officer, group controller, chief accounting officer, group auditor (head of group audit) and external auditor.

Activities during the year

Training

The committee received technical updates from the chief accounting officer on developments in financial reporting and accounting policy. Externally facilitated learning sessions were held on the UK government programme on cyber-security, global trends in fraud and corruption and developments in oil and gas accounting.

Financial disclosure

The committee reviewed the quarterly, half-year and annual financial statements with management, focusing on the integrity and clarity of disclosure, compliance with relevant legal and financial reporting standards and the application of critical accounting policies and judgements.

In conjunction with the SEEAC, the committee examined whether the *BP Annual Report 2013* was fair, balanced and understandable and provided the information necessary for shareholders to assess the group s performance, business model and strategy. The process the two committees and then the full board undertook as part of this examination is outlined in the introduction from the chairman in the Governance overview (see page 69).

Accounting judgements and estimates

Areas of significant judgement considered by the committee during the year and how these were addressed included:

Oil and natural gas accounting

BP uses judgement and estimations when accounting for oil and gas exploration, appraisal and development expenditure and determining the group s estimated oil and gas reserves. The committee reviewed judgemental aspects of oil and gas accounting as part of the company s quarterly due diligence process. It also examined the governance framework for the oil and gas reserves process, training for staff and developments in regulations and controls.

Recoverability of asset carrying values

Determination as to whether and how much an asset is impaired involves management judgement and estimates on highly uncertain matters such as future pricing or discount rates. Judgements are also required in assessing the recoverability of overdue receivables and deciding whether a provision is required.

The committee reviewed the discount rates for impairment testing as part of its annual process and examined the assumptions for long-term oil and gas prices and refining margins. Following political and economic developments in Egypt, the committee reviewed at each quarter with management whether the group s financial assets were impaired.

Table of Contents

Audit committee focus in 2013

*Undertaken jointly with the SEEAC.

Acquisitions of interests in other entities

BP exercises judgement when assessing the level of control obtained in a transaction to acquire an interest in another entity and when determining the fair value of assets acquired and liabilities assumed. The committee examined the accounting for BP s transaction with Rosneft and the judgement on whether the group has significant influence over Rosneft, as where such influence exists, equity accounting is applied resulting in the recognition of BP s share of Rosneft s results each quarter and the reporting of BP s share of production and hydrocarbon reserves. During the year the committee received reports from management and the external auditor which assessed the extent of significant influence, including BP s participation in decision making through director election to the Rosneft board and other factors.

Taxation

Computation of the group s tax expense and liability, the provisioning for potential tax liabilities and the level of deferred tax asset recognition in relation to accumulated tax losses are underpinned by management judgement. The committee reviewed the judgements exercised on tax provisioning as part of its annual review of key provisions.

Derivative financial instruments

BP uses judgement when estimating the fair value of some derivative instruments in cases where there is an absence of liquid market pricing information for example, long-term gas contracts which have a lengthy duration. This approach is taken for the group s longer-term, structured derivative products, natural gas embedded derivatives and the forward contracts entered into in 2012 to purchase shares in Rosneft. The committee received reports from the external auditor on the valuation models developed for these contracts and reviewed disclosures relating to these instruments in the notes to the financial statements.

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. Most of these decommissioning events are in the long term and the requirements that will have to be met when a removal event occurs are uncertain. Judgement is applied by the company when estimating issues such as settlement dates, technology and legal requirements. The committee received briefings on the group s decommissioning, environmental remediation and litigation provisioning, including key assumptions used, the governance framework applied (covering accountabilities and controls), discount rates and the movement in provisions over time.

Gulf of Mexico oil spill

Judgement was applied during the year to the significant uncertainties over the provisions and contingencies relating to the incident.

The committee regularly discussed the provisioning for and the disclosure of contingent liabilities relating to the Gulf of Mexico oil spill with management and the external auditors, including as part of the review of BP s stock exchange announcement at each quarter end.

The committee examined developments relating to the interpretation of the business economic loss claims element of the company s settlement with the Plaintiffs Steering Committee, including US court rulings and monitored legal developments whilst considering the impacts on the financial statements and other disclosures.

Pensions and other post-retirement benefits

Accounting for pensions and other post-retirement benefits involves judgement about uncertain events, including discount rates, inflation and life expectancy. The committee examined the assumptions used by management as part of its annual reporting process.

Risk reviews

The group risks allocated to the audit committee for monitoring in 2013 included risks associated with trading activities, compliance with applicable laws and regulations and security threats against BP s digital infrastructure. For 2014, the board has agreed that the committee will maintain monitoring of the same group risks. The committee held in-depth reviews of these group risks over the year, examined succession planning and capability development in the finance function and reviewed the effectiveness and efficiency of the capital investment of a number of BP s major projects.

Internal control and risk management

The committee reviewed the group s system of internal control and risk management over the year, holding a joint meeting with the SEEAC to discuss key audit findings and management s actions to remedy significant issues. The committee reviews the scope, activity and effectiveness of the group audit function and met privately with the general auditor and his segment and functional heads during the year.

The committee received quarterly reports on the findings of group audit, on identified fraud and misconduct and on key ethics and compliance issues. A further joint meeting with the SEEAC was held to discuss the annual certification report of compliance with the BP code of conduct. The two committees also met to discuss the group audit and ethics and compliance programmes for 2013. The committee held a private meeting with the group ethics and compliance officer during the year.

External audit

The external auditors started the audit cycle with their plan which identified key audit risks to be monitored during the year including exposures relating to the Gulf of Mexico oil spill, estimation of oil and gas reserves, estimation of pension liabilities, recoverability of the group s financial assets in Egypt and future commodity prices and their impact on the carrying value of the group s assets. The committee received updates during the year on the audit process, including how the auditors had challenged the group s assumptions on these issues.

Table of Contents

The audit committee annually reviews the fee structure, resourcing and terms of engagement for the external auditor. Fees paid to the external auditor for the year were $53 million, of which 9% was for non-assurance work (see Financial statements Note 37). Non-audit or non-audit related assurance fees were $5 million (2012 $7 million). The $2-million reduction in non-audit fees relates primarily to reduced corporate finance transactions and lower tax advisory services. 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 this fee.

The effectiveness of the audit process was evaluated through a committee review and a survey of employees in the group s finance function. The 2013 evaluations concluded that there was a good quality audit process and that the external auditors were regarded as knowledgeable and capable, with an ability to challenge the BP team constructively and to ensure balanced reporting. There was also support for the independence of the external auditors and feedback that they should continue sharing good industry practice.

The committee held private meetings with the external auditors during the year and the committee chair met privately with the external auditor before each meeting.

Auditor appointment and independence

The committee considers the reappointment of the external auditor each year before making a recommendation to the board and shareholders. The committee assesses the independence of the external auditor on an ongoing basis and the external auditor is required to rotate the lead audit partner every five years and other senior audit staff every seven years. No

partners or senior staff associated with the BP audit may transfer to the group. The current lead partner has been in place since the start of 2013.

Audit tendering

During the year the committee considered the group s position on its audit services contract following changes to the UK Corporate Governance Code and proposed European Union regulations concerning the audit market. The committee examined a number of options regarding the timing of tendering for BP s external audit, including the mandatory rotation of the group s audit firm envisaged by proposed European regulations.

In view of the uncertainty regarding the form and impact of these regulations, the committee concluded that the best interests of the group and its shareholders would be served by utilizing the transition arrangements outlined by the FRC and retaining BP s existing audit firm until the conclusion of the term of its current lead partner. Accordingly the committee intends that the audit contract will be put out to tender in 2016, in order that a decision can be taken and communicated to shareholders at BP s AGM in 2017; the new audit services contract would then be effective from 2018.

Non-audit services

Audit objectivity and independence is safeguarded through the limitation of non-audit services to tax and audit-related work which falls within defined categories. BP s policy on non-audit services states that the auditors may not perform non-audit services that are prohibited by the SEC, Public Company Accounting Oversight Board (PCAOB) and UK Auditing Practices Board (APB). The categories of approved and prohibited services are outlined below.

The audit committee approves the terms of all audit services as well as permitted audit-related and non-audit services in advance. The external

Permitted and non-permitted audit services

Permitted services

Audit related

- Advice on accounting, auditing and financial reporting.
- Internal accounting and risk management control reviews.
- Non-statutory audit.
- Project assurance/advice on business and accounting process improvement.
- Due diligence (acquisition, disposals, joint arrangements).

Tax services

- Tax compliance.
- Direct and indirect tax advisory services.
- Transaction tax advisory services.
- Assistance with tax audits and appeals.
- Tax compliance/advisory relating to human capital and performance/reward.
- Transfer pricing advisory services.
- Tax legislative monitoring.
- Tax performance advisory.

Other services

- Workshops, seminars and training on an arm s length basis.
- Assistance on non-financial regulatory requirements.
- Provision of independent third-party audit on BP s Conflict Minerals Report.

Prohibited services

SEC principles of auditor independence

- Book keeping/other services related to financial records.
- Financial information systems design and implementation.
- Appraisal, valuation, fairness opinions, contribution in-kind.
- Actuarial services.
- Internal audit outsourcing.
- Management functions.
- HR functions.
- Broker-dealer, investment advisor, banking services.
- Legal services.
- Expert services unrelated to audit.

PCAOB ethics and independence rules

- Contingent fees.
- Confidential or aggressive tax position transactions.
- Tax services for persons in financial reporting oversight roles.

auditor is only considered for permitted non-audit services when its expertise and experience of the company is important. A two-tier system for approval of audit-related and non-audit work operates. For services relating to accounting, auditing and financial reporting matters, internal accounting and risk management control reviews or non-statutory audit, the committee has agreed to pre-approve these services up to an annual, aggregate level. For all other services which fall under the permitted services categories, approval above a certain financial amount must be sought on an individual engagement basis. Any proposed service not included in the permitted services categories must be approved in advance either by the audit committee chairman or the audit committee before engagement commences. The audit committee, chief financial officer and group controller monitor overall compliance with BP s policy on audit-related and non-audit services, including whether the necessary pre-approvals have been obtained.

Committee review

The audit committee undertakes an annual evaluation of its performance and effectiveness. In 2013 the committee used an online survey which examined governance processes such as the mix of experience and skills amongst members, meeting content, information, training and resources. Areas of focus for 2014 arising from the evaluation included monitoring the length of committee papers, the inclusion of broader business topics on the agenda and suggestions for further committee training.

Safety, ethics and environment assurance committee (SEEAC)

Chairman s introduction

The SEEAC has continued to monitor closely and provide constructive challenge to management in the drive for safe and reliable operations at all times. This has included the committee receiving specific reports on the company s management of high priority risks in shipping, wells, pipelines, facilities and non-operated joint arrangements. The committee has also undertaken a number of field visits as described in more detail below as well as maintained its schedule of regular meetings with executive management.

The SEEAC has continued to receive regular reports from the independent experts that it has engaged in both the Upstream (Carl Sandlin) and in the Downstream (Duane Wilson). They have provided valuable insights and advice on many aspects of process safety and we are grateful to them for their work.

Paul Anderson

Committee chair

Role of the committee

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. This includes the committee monitoring the management of personal and process safety and receiving assurance that processes to identify and mitigate such non-financial risk are appropriate in design and effective in implementation.

Key responsibilities

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, group 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.

The committee met seven times in 2013, including joint meetings with the audit committee. At one of the joint meetings the committee reviewed the general auditor s report on the system of internal control and risk management for the year in preparation for the board s report to shareholders in the annual report (see Internal Control Revised Guidance for Directors (Turnbull) on page 110). In that joint meeting the committees also reviewed the general auditor s 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, all of the SEEAC meetings were attended by the group chief executive, the executive vice president for safety and operational risk (S&OR) and the general auditor or his delegate. 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 and the group ethics and compliance officer also attended certain meetings. The committee scheduled private sessions for the committee 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.

Members

Name	Membership status
Paul Anderson (chairman)	Member since February 2010; chairman since December 2012
Frank Bowman	Member since November 2010
Antony Burgmans	Member since February 2004
Cynthia Carroll	Member since June 2007
Ann Dowling	Member since February 2012

Activities during the year

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.

During the year the committee received specific reports on the company s management of risks in shipping, wells, pipelines, facilities and non-operated joint arrangements. The committee reviewed these risks, and risk management and mitigation, in depth with the relevant executive management.

Independent expert Upstream

Mr Carl Sandlin continued in his role as an independent expert to provide further oversight and assurance regarding the implementation of the Bly Report recommendations. He has twice reported directly to the SEEAC in 2013, and presented detailed reports on his work, including reporting on a number of visits he has made to company operations around the world. He will again report to SEEAC in early 2014.

Table of Contents

SEEAC focus in 2013

*Undertaken jointly with the audit committee.

Process safety expert Downstream

Mr Duane Wilson continued to report to the committee in his role as process safety expert for the Downstream segment. In this role he continues to work with segment management on a worldwide basis (having previously focused on US refineries) to monitor and advise on the process safety culture and learnings across the segment. He twice reported directly to the SEEAC in 2013 and presented detailed reports on his work (including reporting on a number of visits he has made to refineries and other downstream facilities).

Reports from group audit and group ethics & compliance

The committee received quarterly reports from both of these functions. These included summaries of investigations into significant alleged fraud or misconduct. In addition, both the general auditor and the group ethics and compliance officer met in private with the chairman and other members of the committee.

Field trips

In April the chairman and all other members of the committee visited Alberta, Canada to examine the oil sands being developed there by the group and third parties. In October a committee member visited operations at the Tangguh LNG facility in West Papua in Indonesia while another committee member travelled to Alaska and visited operations on the North Slope. In addition, three members of the committee visited the Gelsenkirchen refinery in Germany. In all cases, the visiting committee members received briefings on operations and the status of local operating management system (OMS) implementation and risk management and mitigation. For each visit, committee members then reported back in detail to the committee and subsequently to the full board.

Committee review

For its 2013 evaluation, the SEEAC used a questionnaire administered by external consultants to examine the committee s performance and effectiveness. The committee responded to the same questions used in 2012 so that any change trends could be discerned. The topics covered included the balance of skills and experience among its membership, the quality and timeliness of the 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 generally positive. Committee members considered that the committee possessed the right mix of skills and background, had an appropriate level of support and had received open and transparent briefings from management. The committee considered that the field trips made by its members had become an important element in the work of the committee, in particular through such trips giving committee members the ability to examine how risk management is being embedded in businesses and facilities.

Gulf of Mexico committee

Introduction from committee chairman

The Gulf of Mexico committee continues to oversee the group s response to the Deepwater Horizon accident, ensuring that the company fulfils all of its legitimate obligations whilst protecting and defending the interests of the group. In the past year, the focus has been on the review of ongoing proceedings in multi-district litigation 2179 and 2185; of the assessment of natural resource damages; and of a number of other legal proceedings in relation to the Deepwater Horizon accident.

I believe the committee has been thorough in the execution of its duties. The high frequency of meetings and long tenure of committee membership has enabled members to review an evolving and complex spectrum of issues.

Ian Davis

Committee chair

Role of the committee

The Gulf of Mexico committee was formed in July 2010 to oversee the management and mitigation of legal and licence-to-operate risks arising out of the Deepwater Horizon accident and oil spill. The committee s work is integrated with that of the board, which retains ultimate accountability for oversight of the group s response to the accident.

Table of Contents

GoM committee focus in 2013

Key responsibilities

- Oversee the legal strategy for litigation, investigations and suspension/ debarment actions arising from the accident and its aftermath, including the strategy connected with settlements and claims.
- Review the environmental work to remediate or mitigate the effects of the oil spill in the waters of the Gulf of Mexico and on the affected shorelines.
- Oversee management strategy and actions to restore the group s reputation in the United States.
- Review compliance with government settlement agreements arising out of the Deepwater Horizon accident and oil spill, including the SEC Consent Order and the Department of Justice Plea Agreement, in coordination with other committee and board oversight.

Members

Name	Membership status
Ian Davis (chair)	Member since July 2010; committee chair since July 2010
Paul Anderson	Member since July 2010
Frank Bowman	Member since February 2012
George David	Member since July 2010

Activities during the year

The committee reviewed plans and progress in moving Gulf Coast shoreline response activities through to completion and sign-off by the US Coast Guard. Activities are now complete in all states with the exception of Louisiana.

The committee continued to oversee numerous legal matters relating to the Deepwater Horizon accident, including the company s appeals to the US Court of Appeals for the Fifth Circuit relating to the Court-Supervised Settlement Program and the first two phases of trial in MDL-2179.

The committee met thirteen times in 2013.

Committee review

Each year the Gulf of Mexico committee evaluates its performance and effectiveness. In 2013, the committee again used a questionnaire administered by external consultants covering the same questions used in 2012 in order to identify trends. Key areas covered included the balance of skills and experience among its membership, quality and timeliness of information and support received by the committee, the appropriateness of committee tasks and how well the committee communicates its activities and findings to the board. The results of the evaluation were positive.

Specific areas identified for focus in 2014 included maintaining constructive and challenging engagement with management and of continuing timely and effective communication of its activities and findings to the board.

Nomination and chairman s committees

Chairman s introduction

I am pleased to report on the two board committees which I chair. Both have been active during the year in seeking to develop the membership of the board and its governance.

Nomination committee

Role of the committee

The committee ensures an orderly succession of candidates for directors and company secretary.

Key tasks

- Identify, evaluate and recommend candidates for appointment or reappointment as directors.
- Identify, evaluate and recommend candidates for appointment as company secretary.
- Keep under review the mix of knowledge, skills and experience of the board to ensure the orderly succession of directors.
- Review the outside directorship/commitments of the non-executive directors.

Table of Contents

Members

Name	Membership status
Carl-Henric Svanberg (chair)	Member since September 2009; committee chair since January 2010
Paul Anderson	Member since April 2012
Antony Burgmans	Member since May 2011
Cynthia Carroll	Member since May 2011
Ian Davis	Member since August 2010
Brendan Nelson	Member since April 2012

Andrew Shilston, as the senior independent director, attends all meetings of the committee.

Activities during the year

The committee met four times during the year. At the start of the year, the committee reflected on the output of the annual evaluation and determined a rhythm for their meetings during the year. This would include one longer meeting which would review board composition and skills in the light of the company strategy.

The committee considered the time commitment required from non-executive directors and in particular chairs of committees in discharging their responsibilities. The committee determined that the time commitment of directors had increased and this should be made clear to those who may join the board.

The membership of the board had been substantially refreshed over the previous three years which has resulted in no director now being scheduled to retire earlier than the 2016 AGM. Therefore the committee during the year reviewed the current skills of the board and those required by the board over the coming years as the company s strategy is implemented.

In conducting this review the committee initiated interviews with all directors. The conclusion of the review was that whilst the current board s skills matched those presently required, in seeking future candidates there should be a greater focus on the business of BP, US government relations and, possibly, Russia. All of this was against the background of the board s clear aspirations on diversity and the work of the international advisory board in supporting the chairman and the chief executive on geo-political issues.

As part of the review, directors were asked to comment on how the board should work in future given that the company had substantially emerged from the crisis in the Gulf of Mexico. The main conclusions were:

- The board was moving towards a more normal rhythm. Its operation had improved over the past three years. The goal should be simplification and clarity in materials and discussion. Substantial progress had been made.
- The board should continue its focus on strategy and performance, with the committees taking the lead on monitoring. Tasks of the board and committees and their agendas should be reviewed to ensure that the board was addressing the relevant strategic challenges and the committees were complete in their monitoring task.

There should be further focus on major projects and capital investment to ensure that value was being created. Against this background, the committee continued to work with an executive search firm to identify potential candidates and to engage with them as appropriate. The committee was aware of the board s aspirations on gender diversity. It is important, in the committee s view, that any candidates have the requisite skills to join the board. Potential candidates with a diverse background have been identified, and it is anticipated that an appointment will now likely be made in 2014.

Finally, the committee reviewed the current composition of the board and independence of non-executive directors, and recommended to shareholders all directors for re-election at the 2013 AGM.

Committee review

The committee undertook an annual evaluation of its effectiveness and performance, using a questionnaire. The review concluded that there had been an improvement in the timeliness of distribution of pre-read and that the longer session focusing on board composition, skills and the fit with the group s strategy had been valuable and should be repeated annually.

Chairman s committee

Role

To provide a forum for matters to be discussed amongst the non-executive directors.

Tasks

- Evaluate the performance and the effectiveness of the group chief executive (GCE).
- Review the structure and effectiveness of the business organization of BP.
- Review the systems for senior executive development and determine the succession plan for the GCE, the executive directors and other senior members of executive management.
- Determine any other matter which is appropriate to be considered by all of the non-executive directors.
- Opine on any matter referred to it by the chairman of any committees comprised solely of non-executive directors.

Members

The committee comprises all the non-executive directors who join the committee at the date of their appointment to the board. The chief executive attends the committee when requested.

Activities

The committee met six times during the year.

The committee reviewed:

- The performance of the chairman and the chief executive early in the year. Parameters were set for evaluations in 2014.
- The developing position in the US Courts in respect of the implementation of the settlement with the Plaintiffs Steering Committee, including the business economic loss claims and the activities of the Claims Administrator, the federal judge and the appeals court. The work of Judge Freeh was also considered.

A number of issues relating to the company s strategy in the light of the views of shareholders and the market more generally.

The chief executive s succession plans for the executive team and senior leaders. The committee also considered the organization and operation of the executive team.

Table of Contents

Table of Contents

Chairman s annual statement

Dear shareholder

BP continued the disciplined and systematic execution of its strategy during 2013, focusing on safety and operational risk management, and on restoring value. As in 2012, there were many positive steps in the recovery journey during 2013 including improved safety, a strengthened portfolio and a new future in Russia. I encourage you to read about these in more detail elsewhere in this annual report.

Remuneration for executive directors continues to be tied closely to this overall recovery of the group. The vast majority of potential remuneration is based on outcomes relative to measures related directly to the company s strategy and key performance indicators. In addition to a direct link to strategy, our remuneration system has a strong bias towards sustained long-term performance, and our decisions regarding remuneration are guided by key principles of informed judgement, fair treatment and alignment with shareholders. My meetings with shareholders this year have again been helpful in understanding perspectives and have led to a few modifications to our policy.

Our report this year reflects the new UK regulations on directors remuneration and so is divided into an annual report on remuneration and a separate policy report. The annual report on remuneration sets out and explains the outcomes of the various elements that make up 2013 total remuneration. The policy report explains our proposed remuneration policy for the next three years which, subject to approval by shareholders, will come into effect from the AGM. For both sections the information relating to executive directors (whose remuneration is determined by the remuneration committee) is presented separately from that relating to non-executive directors (whose remuneration is determined by the full board).

2013 outcomes

I am pleased to report that remuneration for 2013, as summarized on page 85, increased after several years where pay was significantly depressed by the aftermath of the Deepwater Horizon incident. It is particularly encouraging that a moderate portion of shares in the long-term performance share plan has vested this year. These outcomes reflect strong and sustained performance with safety steadily improving, operations performing well and a portfolio of assets growing through capital discipline and strong project management. The significant divestments of the last few years have made the company smaller but stronger, with improved potential to grow value.

Annual bonus

It was a good year for BP with improved safety, new discoveries and operations, a strengthened portfolio and benefits already accruing from the company s new relationship in Russia. Overall group performance exceeded annual plan levels and resulted in a score of 1.32 times target. Performance was assessed relative to metrics set at the start of the year and reflecting the company s strategy and key performance indicators.

Safety and operational risk management accounted for 30% of annual bonus. Led strongly from the top, this continued to show encouraging progress with particularly significant reductions in tier 1 process safety events and loss of primary containment both important measures of process safety. Results this year confirm that it remains a constant priority throughout the business.

The company also made good gains in restoring value, which accounted for 70% of annual bonus. Underlying replacement cost profit and total cash costs were both better than plan targets, while operating cash flow achieved target levels. Key operating performance was also positive with important major projects commissioned and a significant improvement in unplanned Upstream deferrals. Downstream operations demonstrated high availability and good safety results but profitability was impacted by a difficult business environment affecting refinery margins.

Deferred bonus

The first of the deferred bonus share awards, implemented in 2010, became eligible for vesting at the end of 2013. Vesting was dependent on safety and environmental sustainability performance over the period from 2011 through 2013. Our review confirmed very positive results during this period with consistent improvements in key metrics and no major incidents. Based on this positive result, the deferred and matched shares for this period vested fully.

Performance shares

The 2011-2013 performance share plan, the first plan commencing after the Deepwater Horizon incident, focused on value creation, reinforcing safety and risk management and rebuilding trust. 50% of the award was dependent on total shareholder return which failed to make the threshold required for vesting. Reserves replacement, accounting for 20% of the award, is expected to be very positive and progress relative to the strategic imperatives, accounting for the remaining 30%, was very encouraging. Overall, we expect nearly 40% of shares will vest, the highest in over 10 years.

Other elements

Salaries were increased by just under 3% for Bob Dudley, Iain Conn and Dr Brian Gilvary mid-year. Pension increases reflect normal plan rules and valuation according to UK regulations. The increased value reported for Bob Dudley reflects his promotion to group chief executive in 2010 which, because his defined benefit pension is based on three-year average remuneration, takes a number of years to reach a steady state. In addition, the reported value is calculated according to UK regulations and the committee has been informed by the company s consulting actuaries that these significantly overstate the value of his US pension increase.

Remuneration policy

Attracting and retaining top talent is a key objective of our approach to remuneration. Our proposed policy, as summarized on page 98, remains largely unchanged from that which has applied for a number of years and its continuity has been a stabilizing force during a period of company turbulence. The core elements of salary, annual bonus, deferred bonus, performance shares and pension continue to provide an effective, relatively simple, performance-based system that fits well with the long-term nature of BP s business and strategy.

Three modifications have been included in our proposed policy as a result of our dialogue with investors. First, we have added a three-year retention period in the deferred bonus element for those matched shares that vest in the plan. Second, we have made the vesting of performance shares more stringent for those metrics based on performance relative to other oil majors. Finally, we have added a specific review of performance share vesting to ensure that high levels of vesting are consistent with shareholder benefits.

All of the above are explained in more detail in the policy report.

Table of Contents

EDIP renewal

The executive directors incentive plan (EDIP) has provided the umbrella framework for share-based remuneration for BP executive directors since it was first approved by shareholders in April 2000. It was renewed both in 2005 and 2010 and will expire in April 2015 according to its current mandate. The UK Listing Rules require a separate approval for this plan despite it largely being a duplication of what is included in the new policy report governed by a different regulatory regime. Given that the EDIP is an important vehicle to implement the remuneration policy, we concluded that it was appropriate to bring its renewal forward to coincide with the first

policy vote. Details appear under resolution 19 in the Notice of Meeting, and are consistent with those included in the policy report.

It is reassuring to see momentum building in the business, led by a talented top team with resolve and commitment. Our remuneration system has worked appropriately during difficult times, and I am confident it will continue to do so as and when performance returns to healthy sustained levels.

Antony Burgmans

Chairman of the remuneration committee

6 March 2014

Remuneration the big picture

Table of Contents

2013 annual report on remuneration

This section reports on the remuneration outcomes for 2013 and is divided into separate sections for executive and non-executive directors.

The remuneration of the executive directors is set by the remuneration committee (the committee) under delegated powers from the board. The committee makes a recommendation to the board for the remuneration of the chairman. The remuneration of the non-executive directors is set by the board based on a recommendation from the chairman, the group chief executive and the company secretary.

(a) Executive directors

Total remuneration summary

Strategy > Key performance indicators > Performance > Pay

The clear link from strategy through to pay continues. For several years the company s strategy has centred on enhancing safety and risk management, rebuilding trust and restoring value. This strategy has provided focus for key performance indicators (KPIs) and in turn the measures for annual bonus, deferred bonus and performance share plans.

2013 summary of outcomes

These are shown in the table opposite and represent the following:

Salary reviewed mid-year and **increased just under 3%** for all except Dr Byron Grote who retired mid-year.

Annual bonus overall group bonus was based 30% on safety and operational risk (S&OR) management and 70% on restoring value. S&OR results were good both in terms of improvement and overall standard. Similarly, performance relative to value measures was overall better than the annual plan. **Overall group outcome was 1.32 times target level.**

The resulting cash bonuses are shown in the table opposite with total deferred bonuses reflected in the Conditional equity table as required by UK regulations. Dr Byron Grote, given his retirement, was not eligible for any deferral, and his bonus (prorated to reflect his service) was paid in cash.

Deferred bonus the 2010 deferred bonus was contingent on safety and environmental sustainability performance over the period 2011 through 2013. Overall assessment was very positive based on continually improving safety and risk management performance and strong evidence of ingrained safety culture and systems throughout the organization. Based on this, **2010 deferred and matched shares vested**.

Performance shares the 2011-2013 plan was based 50% on total shareholder return (TSR) and 20% on reserves replacement, both relative to the other oil majors, and reflecting the key strategic focus on restoring value. The final 30% was based on strategic imperatives made up equally of safety and risk management, external reputation and staff alignment and morale all key strategic priorities in the period after the Deepwater Horizon incident in 2010. **39.5% of shares in the plan are expected to vest** based on strong reserves replacement performance and good progress against all three strategic imperatives. TSR performance did not achieve the minimum level required for any vesting.

Pension pension figures reflect the UK requirements to show 20 times the increase in pension value for defined benefit schemes, as well as any cash paid in lieu. In the case of Bob Dudley s reported figures, this UK requirement overstates the increase in the actuarial value of his US pension by several million dollars.

Table of Contents

Single figure table of remuneration of executive directors in 2013 (audited)

Remuneration is reported in the currency received by the individual

	Bob Dudley thousand		Iain Conn thousand		Dr Brian Gilvary thousand		Dr Byron Grote thousand	
Annual remuneration 2013	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Salary	**$1,776**	$1,726	**£763**	£741	**£700**	£690	**$743**	$1,464
Annual cash bonus[a]	**$2,344**	$837	**£961**	£374	**£924**	£366	**$1,470**	$710
Benefits	**$90**	$86	**£59**	£39	**£45**	£13	**$10**	$15
Total	**$4,210**	$2,649	**£1,783**	£1,154	**£1,669**	£1,069	**$2,223**	$2,189
Vested equity								
Deferred bonus and match[b]	**$0**	$0	**£242**	£0	**£0**	£0	**$893**	$0
Performance shares	**$4,522[c]**	$0	**£1,332[c]**	£666	**£505[c]**	£299	**$2,225[c]**	$0
Total	**$4,522**	$0	**£1,574**	£666	**£505**	£299	**$3,118**	$0
Total remuneration	**$8,732**	$2,649	**£3,357**	£1,820	**£2,174**	£1,368	**$5,341**	$2,189
Pension								
Pension value increase[d]	**$4,447**	$6,535[e]	**£46**	£0	**£44**	£1,024	**$141**	$747
Cash in lieu of future accrual[f]	**N/A**	N/A	**£267**	£259	**£245**	£242	**N/A**	N/A
Total including pension	**$13,179**	$9,184	**£3,670**	£2,079	**£2,463**	£2,634	**$5,482**	$2,936

[a] This reflects the amount of total overall bonus paid in cash with the deferred portion set out in the conditional equity table below. The relevant portions are two-thirds cash and one-third deferred.

[b] This relates to the deferred bonus from prior years that vests.

[c] Represents the assumed vesting of shares in 2014 following the end of the relevant performance period, based on anticipated performance achieved under the rules of the plan and includes re-invested dividends on shares vested. In accordance with UK regulations, the vesting price of the assumed vesting is the average market price for the fourth quarter of 2013 which was £4.69 for ordinary shares and $45.52 for ADSs.

[d] Represents the annual increase in accrued pension multiplied by 20 as prescribed by UK regulations. For Bob Dudley the increase in actuarial value of $1,319,000 is considered to be a more accurate reflection of the increase.

[e] The figure for 2012 has been restated on the same basis as 2013 to be consistent with the finalized UK regulations.

[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	
rred bonus in respect onus year		**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2
red s	Value (thousand)	**$1,172**	$1,674	**£481**	£748	**£462**	£732	**$0**	$1,
red erted ares	Shares	**149,628**	229,380	**100,563**	161,296	**96,653**	157,630	**0**	194,
hed s	Shares	**149,628**	229,380	**100,563**	161,296	**96,653**	157,630	**0**	32,
ng		**Feb 2017**	Feb 2016	**Feb 2017**	Feb 2016	**Feb 2017**	Feb 2016	**Feb 2017**	Feb 2
ormance share element		**2013-2015**	2012-2014	**2013-2015**	2012-2014	**2013-2015**	2012-2014	**2013-2015**	2012-2
ntial mum s		**1,384,026**	1,343,712	**694,688**	660,633	**637,413**	624,434	**142,278**	414,
ng		**Feb 2016**	Feb 2015	**Feb 2016**	Feb 2015	**Feb 2016**	Feb 2015	**Feb 2016**	Feb 2

Table of Contents

Total remuneration in more depth

Salary and benefits

2013 outcomes

Salaries were reviewed in May 2013 using a number of internal and external comparisons. Externally, the competitiveness of salaries and of overall packages relative to other oil majors, other large UK and Europe-based international companies and related US companies were considered. Internally the committee reviewed three distinct groups the overall level of increases for all employees in both the UK and the US, the distribution and average level of increases for group leaders comprising around 500 top executives in the company, and finally the individual and average increases for the top executive team.

Based on this review, salaries were increased by 2.8% for Bob Dudley (to $1,800,000), 2.9% for Iain Conn (to £774,000) and 2.9% for Dr Brian Gilvary (to £710,000) effective 1 July 2013.

Total benefits received by executive directors included car-related benefits, security assistance, insurance and medical benefits. The total value of taxable benefits is included in the summary table on page 85.

2014 implementation

The remuneration committee intends to review salaries in May 2014 and will again consider both internal and external comparisons. Benefits will continue unchanged.

Annual bonus

Framework

All executive directors were eligible for an overall annual bonus, including deferral, of 150% of salary at target and 225% of salary at maximum unchanged since 2010.

Bob Dudley s annual bonus was based entirely on group results, as was Dr Brian Gilvary s and Dr Byron Grote s. Iain Conn s was based 70% on group results and 30% on his Downstream segment results.

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 the company s strategy and KPIs. Measures were grouped under the dominant themes of S&OR management, and restoring value. Targets were set so that meeting the 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. Value measures were set to account for 70% of total bonus and included targets for operating cash flow, underlying replacement cost profit, total cash costs, Upstream unplanned deferrals, major project delivery and Downstream net income per barrel.

Additional measures and targets were set for Iain Conn s Downstream segment. These focused on safety, operating efficiency and profitability.

As well as the specific measures set out, the committee considers any other results or factors it deems relevant and applies its overall judgement in determining final bonus outcomes.

2013 annual bonus outcomes

2013 outcomes

Overall group performance outcomes for the year are summarized in the table above.

S&OR management performance, weighted at 30%, was positive. Process safety events declined significantly to amongst the lowest of the oil majors. Loss of primary containment did not meet its target but still showed an improvement of more than 10% over 2012. Recordable injury frequency continued to show marked improvement.

Performance related to value measures were similarly positive. Underlying replacement cost profit and total cash costs both came in better than plan targets while operating cash flow met its plan level. Major projects met plan with one exception and Upstream unplanned deferrals exceeded target with a 30% improvement compared to 2012. Finally, Downstream net income per barrel was below target reflecting difficult trading conditions.

Based on these results, the group performance factor is calculated at 1.32 times target. The committee, as is its normal practice, considered this result in the context of the underlying performance of the group, competitors results, shareholder feedback and input from the board and other committees. After review, it concluded that this represented fairly the overall performance of the business during the year and confirmed the

score for group purposes.

In the Downstream segment, safety results were good with improvement in most areas of process and personal safety. Performance related to value measures was negatively impacted by compression of fuel margins and so operating cash flow was below plan level, but other operating measures were at or better than plan. A performance score of 1.13 times target was achieved.

Overall bonus is determined by multiplying the group score of 1.32 times target by the on-target bonus level of 150% of salary. Bob Dudley s total overall bonus therefore was 198% of salary (1.32x150%). The same score was applied to each of the other executive directors for group outcomes resulting in both Dr Brian Gilvary and Dr Byron Grote also receiving an overall bonus of 198% of salary. Combined with the results for his segment (accounting for 30% of his bonus), Iain Conn s total overall score was 1.26 times target, resulting in a bonus of 189% of salary.

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 election. Dr Byron Grote, who retired mid-year, was not eligible for deferral and so his entire bonus (reflecting his six months of service) was paid in cash.

Table of Contents

2013 overall bonus outcome

	Paid in cash	Total deferred
Bob Dudley	$2,343,660	$1,171,830
Iain Conn	£961,380	£480,690
Dr Brian Gilvary	£924,000	£462,000
Dr Byron Grote	$1,470,150	$0

2014 implementation

For 2014, 100% of Bob Dudley s and Dr Brian Gilvary s bonus will be based on group results. Iain Conn will again have 70% of his bonus determined on group results and 30% on his Downstream segment results.

The committee determines specific measures and targets each year that reflect the priorities in the group s annual plan and KPIs, both of which are derived from the company s strategy. For 2014 there will be no change from the measures and weightings used in 2013 other than a minor change to the treatment of cost management. The table below shows the group measures that will be used, the weight attached to each and the alignment with KPIs and group strategy.

Targets have been agreed for each of the measures based on the annual plan. In addition the committee uses its judgement to set the range of bonus payouts from minimum acceptable at threshold to very stretching but achievable at maximum.

2014 annual bonus measures

Deferred bonus

Framework

One-third of the total bonus awarded to the executive directors is required to be paid in shares under the terms of the deferred bonus element. Deferred shares are matched on a one-for-one basis and, after three years, vesting for both deferred and matched shares is contingent on an assessment of safety and environmental sustainability over the three-year deferral period.

Individuals may elect to defer up to an additional one-third of total bonus into shares on the same basis and subject to the same contingency as the mandatory deferral.

2013 outcomes

No bonuses were paid for group results in 2010, however both Iain Conn and Dr Byron Grote received a limited bonus related to their segment results that year. Deferrals from these were converted to shares, matched one-for-one, and deferred for three years from the start of 2011. The three-year performance period concluded at the end of 2013 and vesting was subject to a review of safety and environmental sustainability performance over the three-year deferral period. The committee reviewed safety and environmental sustainability performance over this period and, as part of this review, sought the input of the safety, ethics and environment assurance committee (SEEAC). Over the three-year period 2011-2013 safety measures showed a steady improvement, there were no major incidents, and the group-wide operating management system showed good signs of driving improvement in environmental as well as safety areas.

Based on their review, the committee approved full vesting of the deferred and matched shares for the 2010 deferred bonus as shown in the following table (as well as in the total remuneration summary chart on page 85).

2010 deferred bonus vesting

Name	Shares deferred	Vesting agreed	Total shares including dividends	Total value at vesting
Iain Conn	42,768	100%	49,340	£241,766
Dr Byron Grote	97,548	100%	110,640	$892,680

Dr Byron Grote s vesting reflected a prorating of the matched shares component to reflect his service. Dr Brian Gilvary participated in a separate deferred bonus plan prior to his appointment as an executive director and details of this are provided in the table on page 93.

Information on the deferred bonus awards made in early 2013, and pertaining to 2012 bonuses, was set out in last year s report and a summary is included in the table on page 85.

2014 implementation

The remuneration committee has determined that the safety and environmental sustainability performance hurdle will continue to apply to shares deferred from the 2013 bonus and that there will be no change to these measures. It has also proposed that in future all matched shares that vest will, after sufficient shares have been sold to pay tax, be subject to an additional three-year retention period before being released to the individual, further reinforcing our long-term orientation. These features are described in more detail in the policy section of the report and have been implemented for shares deferred from the 2013 bonus.

Table of Contents

Performance shares

Framework

Performance shares were awarded to each executive director in early 2011 with vesting after three years dependent on performance relative to measures reflecting the company s strategic priorities in the period after the Deepwater Horizon accident. For the 2011-2013 plan, vesting was based 50% on TSR compared to the peer group, 20% on reserves replacement ratio, also relative to the peer group, and 30% on a set of strategic imperatives for rebuilding trust. These centred on S&OR

management, rebuilding BP s external reputation, and reinforcing staff alignment and morale.

The peer group includes ExxonMobil, Shell, Chevron and Total. ConocoPhillips was originally included as part of the peer group but was removed following its demerger (with no impact on outcome in any case). 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.

2011-2013 performance shares outcome

2013 outcomes

Overall, 39.5% of the shares awarded in the 2011-2013 plan are expected to vest, based on results as shown in the table above.

Relative TSR was weighted heaviest, reflecting the high strategic priority on restoring value. Outcomes failed to meet the threshold required and so no shares vested for this measure.

Reserves replacement has been very positive and we expect that BP will be in second place amongst the oil majors. Since the actual results of the other majors are not publicly available until their respective annual reports are published, the committee will review the outcomes when all information is confirmed and decide then on the final vesting. For the purposes of this report, and in accordance with UK regulations, second place has been assumed. Any adjustment to this will be reported in next year s annual report on remuneration.

The committee s review also concluded that progress against the three strategic imperatives has been positive. S&OR management culture has shown steady improvement and its high importance increasingly embedded in the minds of employees, as demonstrated by our internal surveys. Moreover the S&OR performance metrics have consistently improved including against those of our peers. BP s external reputation has similarly shown steady improvement as measured by external surveys assessing reputation amongst different groups in key countries. Finally, staff alignment and morale has been reassuringly positive in the aftermath of the Deepwater Horizon accident, with internal surveys demonstrating improvements and a high scoring of measures related to group priorities including safety and trust.

As in past years, the committee also considers the overall performance of the company during the period and whether any other relevant factors should be taken into account. Following this review, the committee concluded that a 39.5% vesting was a fair reflection of overall performance pending confirmation of the reserves replacement result. This will result in the vesting as shown in the table below.

2011-2013 performance shares outcome

	Shares awarded	Shares vested inc dividends	Value of vested shares
Bob Dudley	1,330,332	596,028	$4,521,866
Iain Conn	623,025	283,920	£1,331,585
Dr Brian Gilvary	90,000	102,550	£504,509
Dr Byron Grote	654,498	293,232	$2,224,653

Dr Brian Gilvary s vesting reflects awards granted prior to him joining the board under equivalent plans below board level which have vested in early 2014. Dr Byron Grote s award has been prorated to reflect his service prior to retirement.

Information on performance shares awarded in early 2013, relating to the 2013-2015 period, was set out in last year s report and a summary is included in the table on page 85.

Table of Contents

2014 implementation

Shares were awarded in early 2014 to a value of five and a half times salary to Bob Dudley and four times salary to Iain Conn and Dr Brian Gilvary (details of which are shown in the table on page 85). These have been awarded under the performance share element of the executive directors incentive plan (EDIP) and are subject to a three-year performance period, and for those shares that vest are subject, after tax, to an additional three-year retention period.

The 2014-2016 performance share plan will be based on the same measures as used last year and remain aligned directly with the company s strategic priorities and KPIs.

2014-2016 performance shares

TSR and reserves replacement ratio will be assessed on a relative basis compared with the other oil majors Chevron, ExxonMobil, Shell and Total. As set out in the policy report, commencing with the 2014-2016 plan, vesting will be 100%, 80% and 25% for first, second and third place respectively amongst the oil majors and no vesting for fourth or fifth place. The committee has agreed targets and ranges for the other measures that

will be used to assess performance at the end of the three-year performance period. As part of its overall assessment it also considers whether, in the event of high levels of vesting, the result is consistent with benefits achieved by shareholders. Full details are included in the policy report.

Pension

Framework

Executive directors are eligible to participate in company pension schemes that apply in their home countries which follow national norms in terms of structure and levels. Bob Dudley participates in the US plans (as did Dr Byron Grote), 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 103).

	Service at 31 Dec 2013	Total accrued pension at	Additional pension earned	Actuarial value of increase	20 times increase

		31 Dec 2013	during 2013 (net of inflation)	earned during 2013	earned during 2013
			(thousand)		
Bob Dudley (US)	34	$2,050	$222	$1,319	$4,447
Iain Conn (UK)	28	£326	£2	£0	£46
Brian Gilvary (UK)	27	£326	£2	£0	£44
Byron Grote (US)	n/a	$1,416	$7	-$93	$141

2013 outcomes

The table above sets out the change in pension for each of the executive directors for 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. He is entitled, as all former Amoco heritage employees, to receive the greater of the BP or Amoco plans that apply. As part of the transition agreed at the time of merger, the Amoco plan stopped accruing at the end of 2012, and therefore the BP plan applicable to senior US executives will now determine his overall accrued benefit. His total benefit under this plan is calculated as 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) for each year of service (without regard for tax limits) which may be paid from various qualified and non-qualified plans as described in the policy section of this report. The calculations in the above table reflect this transition. The calculations also incorporate the latest bonus reported on when determining the average of the best three successive years bonus in the final average earnings calculation. Last year s numbers have been updated to be on a consistent basis.

Iain Conn and Dr Brian Gilvary participate in UK pension arrangements. 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 2013 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 required by the new UK regulations, as well as the actuarial value increase as previously stipulated have been included in the table above. The summary table on page 85 uses the 20 times additional pension earned figure and the cash supplements are separately identified.

In Bob Dudley s case, the committee has been informed by the company s consulting actuaries, Mercer, that the factor of 20 substantially overstates the increase in value of his pension benefits primarily because his US pension benefits are not subject to cost of living adjustments after retirement, as they are in the UK. They have indicated that a typical annuity factor for such US benefits is around 12, as compared to a UK plan where a factor of 20 is often taken to reflect the increase in value of pension benefits (as well as being required by UK regulations). Therefore the committee considers that the actuarial value of increase identified in the table above more accurately reflects the value of his pension increase.

Table of Contents

Remuneration committee

The committee was made up of the following independent non-executive directors:

Members
Antony Burgmans (chairman)
George David
Ian Davis
Professor Dame Ann Dowling
Carl-Henric Svanberg normally attends the meetings

Committee role

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 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 six times. Key discussions and decision items are shown in the table below.

Remuneration committee 2013 meetings

The board s overall evaluation process included a separate questionnaire on the work of the remuneration committee. The results were analyzed by an external consultant and discussed at the committee s meeting in January 2014. Processes continued to be rated as good to excellent and a number of topics for more in-depth discussion were identified.

Independence and advice

Independence

The committee operates with a high level of independence. The board considers all committee members to be independent with no personal financial interest, other than as shareholders, in the committee s decisions.

Consultation

The group chief executive is consulted on the remuneration of the other executive directors and senior executives 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 group human resources director and head of group reward may attend relevant sections of meetings to ensure appropriate input on matters related to executives below board level.

The committee consults other relevant committees of the board, for example the SEEAC, on issues relating to the exercise of its judgement or discretion.

Advice

Gerrit Aronson, an independent consultant, is the committee s independent adviser. He is engaged directly by the committee. Mr Aronson acts as the secretary to the remuneration committee and advises the chairman, the board and the nomination committee on a variety of governance issues.

During 2013, advice to the committee was received from David Jackson, the company secretary, who is employed by the company and who reports to the chairman of the board. The company secretary periodically reviews the independence of the advisers. Advice and services on particular remuneration matters was received from other external advisers appointed by the committee.

Towers Watson provided information on the global remuneration market, principally for benchmarking purposes. Freshfields Bruckhaus Deringer LLP provided legal advice on specific compliance matters to the committee. Both firms provide other advice in their respective areas to the group.

Total fees or other charges (based on an hourly rate) paid in 2013 to the above advisers for the provision of remuneration advice to the committee as set out above (save in respect of legal advice) is as follows:

Gerrit Aronson £150,000

Towers Watson £85,000

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 held individual meetings with shareholders holding in aggregate more than 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. These meetings supplemented a group meeting of shareholders with all committee chairs and the chairman, as well as an investor relations programme including a regular ongoing dialogue between the chairman and shareholders. This engagement provides the committee with an important and direct perspective of shareholder interests and, together with the voting results on the Directors remuneration report at the AGM, is considered when making decisions.

The committee reviewed remuneration policy during 2013 and, following dialogue with shareholders, made three adjustments to further reinforce our bias towards the long term and sustained performance.

First, a three-year retention period has been introduced to the matched shares that vest in the deferred bonus element.

Table of Contents

Second, a more stringent vesting schedule has been introduced for those metrics in the performance share plan that are based on performance relative to the other oil majors.

Third, a specific review of performance share plan outcomes will take place to ensure high levels of vesting are consistent with shareholder benefits. These are explained in more detail in the policy report.

The shareholder vote from the 2013 AGM is shown below. Total votes withheld represent less than 1% of total shares outstanding.

2013 AGM directors remuneration report vote results

Year	% vote for	% vote against	Votes withheld
2013	94.1%	5.9%	108,843,360

Directors shareholdings

Executive directors are required to develop a personal shareholding of five times salary within a reasonable period of time from appointment. It is the stated intention of the policy that executive directors build this level of personal shareholding primarily by retaining those shares that vest in the deferred bonus and performance share plans which are part of the EDIP. In assessing whether the requirement has been met, the committee takes account of the factors it considers appropriate, including promotions and vesting levels of these share plans, as well as any abnormal share price fluctuations. The table below shows the status of each of the executive directors in developing this level. These figures include the value as at 24 February 2014 from the directors interests shown below plus the assumed vesting of the 2011-2013 performance shares and is consistent with the figures reported in the single figure table on page 85.

	Appointment date	Value of current shareholding	% of policy achieved
Bob Dudley	October 2010	$5,477,092	61%
Iain Conn	July 2004	£3,888,423	101%
Dr Brian Gilvary	January 2012	£2,502,388	71%

The committee is satisfied that all executive directors comply with the policy by building the required personal shareholding in a reasonable period of time following their appointment. Importantly, none of the existing executive directors has sold shares that vested from the EDIP.

Directors interests

The figures below indicate and include all the beneficial and non-beneficial interests of each executive director of the company in shares of BP (or calculated equivalents) that have been disclosed to the company under the Disclosure and Transparency Rules (DTRs) as at the applicable dates.

	Ordinary	Ordinary	Change from	Ordinary shares or

	shares or equivalents at 1 Jan 2013	shares or equivalents at 31 Dec 2013	31 Dec 2013 to 24 Feb 2014	equivalents total at 24 Feb 2014
Bob Dudley	346,008[a]	355,707[a]		355,707[a]
Iain Conn	509,729[b]	600,272[b]	26,231	626,503[b]
Dr Brian Gilvary	331,977	412,973	81,570	494,543
Former executive director	At 1 Jan 2013	At retirement		
Dr Byron Grote	1,512,616[c]	1,512,616[d]		

[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 retirement at 11 April 2013.

The following table shows both the performance shares and the deferred bonus element awarded under the 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 deferred bonus and performance shares elements of the EDIP awarded can be found on pages 93 and 94.

	Performance shares at 1 Jan 2013	Performance shares at 31 Dec 2013	Change from 31 Dec 2013 to 24 Feb 2014	Performance shares total at 24 Feb 2014
Bob Dudley[a]	3,691,950	4,953,654	1,604,178	6,557,832
Iain Conn	2,305,847	2,666,314	818,486	3,484,800
Dr Brian Gilvary[b]	669,434	1,599,607	776,350	2,375,957
Former executive director	Performance shares at 1 Jan 2013	Performance shares at 31 Dec 2013	Change from 31 Dec 2013 to 24 Feb 2014	Performance shares total at 24 Feb 2014
Dr Byron Grote[a]	2,889,192	1,810,686[c]		

[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.
[c] On retirement at 11 April 2013.

At 24 February 2014, the following directors held the numbers of options under the BP group share option schemes over 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 94.

			Options	

		Restricted shares
Bob Dudley		
Iain Conn	3,814	
Dr Brian Gilvary	504,191	80,335
Former executive director	**Options**	**Restricted shares**
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 24 February 2014, all directors and senior management as a group held interests of 9,632,638 ordinary shares or their calculated equivalent, 12,418,589 performance shares or their calculated equivalent and 6,058,172 options over ordinary shares or their calculated equivalent under the BP group share option schemes.

Executive director leaving the board

Dr Byron Grote retired from the board at the 2013 AGM and after a transition period, retired from the company at the end of June 2013. The terms of his departure were reported last year but are reiterated here for completeness. Under the rules of the EDIP, his outstanding performance share awards pertaining to 2011-2013, 2012-2014, and 2013-2015 performance periods, as well as the matching share awards in respect of the 2010, 2011 and 2012 deferred bonus have been 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 have been met. His 2013 bonus eligibility was likewise prorated to reflect his service and based on group results for the year. He has not received any termination payments on leaving service.

Table of Contents

Remuneration statistics and comparisons

The information below is provided according to the requirements and definitions included in UK regulations.

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 £117.33 and £188.41 respectively.

History of CEO remuneration

Year	CEO	Total remuneration (thousand)[a]	Annual bonus % of maximum	Performance share vesting % of maximum
2009	Hayward	£6,753	89%[b]	17.5%
2010[c]	Hayward	£3,890	0%	0%
	Dudley	$7,722	0%	0%
2011	Dudley	$8,312	67%	16.7%
2012	Dudley	$9,184	65%	0%
2013	Dudley	$13,179	88%	39.5%

[a] Total remuneration figures include pension and are shown as reported each year in the respective directors remuneration report with the exception of 2012 which is restated in line with the figure reported in the single figure table in this report.
[b] 2009 annual bonus did not have an absolute maximum and so is shown as a percentage of the maximum established in 2010.
[c] 2010 figures show full year total remuneration for both Hayward and Dudley, although Dudley did not become CEO until October 2010.

Relative importance of spend on pay

Key expenditure areas	2013 (million)	2012 (million)	% change
Remuneration paid to all employees[a]	$13,654	$13,448	1.5%
Distributions to shareholders (total)	$12,404	$6,276	97.6%

Dividends[b]	$6,911	$6,276	
Buybacks[c]	$5,463	$0	
Capital investment[d]	$24,600	$23,950	2.7%

[a] Total remuneration reflects overall employee costs. See Financial statements Note 33 for further information.

[b] Dividends includes both scrip dividends as well as those paid in cash. See Financial statements Note 12 for further information.

[c] See Financial statements Note 31 for further information.

[d] Capital investment reflects organic capital expenditure. See footnote d on page 236 for further information.

Percentage change in CEO remuneration

Comparing 2013 to 2012	Salary	Benefits	Bonus
% Change in CEO remuneration	2.8%	4.7%	40%
% Change in comparator group remuneration[a]	3.3%	0%[b]	30%

[a] The comparator group comprises some 40% of BP s global employee population being professional/managerial grades of employees based in the UK and US and employed on more readily comparable terms.

[b] There was no change in employee benefits level overall. Those benefits that are linked to salary have changed in line with base salary increases.

Table of Contents

Further details

Deferred shares (audited)[a]

				Deferred share element interests				Interests vested in 2	
				Potential maximum deferred shares				Number of ordinary shares	
year	Type	Performance period	Date of award of deferred shares	At 1 Jan 2013	Awarded 2013	At 31 Dec 2013	Awarded 2014	vested	Vesting d
2011[c]	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[d]	Comp	2013-2015	11 Feb 2013		114,690	114,690			
	Vol	2013-2015	11 Feb 2013		114,690	114,690			
	Mat	2013-2015	11 Feb 2013		229,380	229,380			
2013[d]	Comp	2014-2016	12 Feb 2014				149,628		
	Mat	2014-2016	12 Feb 2014				149,628		
2010	Comp	2011-2013	09 Mar 2011	21,384		21,384		24,670[f]	12 Feb 20
	Mat	2011-2013	09 Mar 2011	21,384		21,384		24,670[f]	12 Feb 20
2011[c]	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[d]	Comp	2013-2015	11 Feb 2013		80,648	80,648			
	Vol	2013-2015	11 Feb 2013		80,648	80,648			
	Mat	2013-2015	11 Feb 2013		161,296	161,296			
2013[d]	Comp	2014-2016	12 Feb 2014				100,563		
	Mat	2014-2016	12 Feb 2014				100,563		
2009	DAB[e]	2010-2012	15 Mar 2010	87,394				95,279[f]	15 Jan 20
2010	DAB[e]	2011-2013	14 Mar 2011	44,971		44,971		51,118[f]	09 Jan 20
2011[h]	DAB[e]	2012-2014	15 Mar 2012	73,624		73,624			
2012[d]	Comp	2013-2015	11 Feb 2013		78,815	78,815			
	Vol	2013-2015	11 Feb 2013		78,815	78,815			
	Mat	2013-2015	11 Feb 2013		157,630	157,630			
2013[d]	Comp	2014-2016	12 Feb 2014				96,653		
	Mat	2014-2016	12 Feb 2014				96,653		
ector									
2010	Comp	2011-2013	09 Mar 2011	26,604		26,604		30,174[f]	12 Feb 20
	Vol	2011-2013	09 Mar 2011	26,604		26,604		30,174[f]	12 Feb 20

	Mat	2011-2013	09 Mar 2011	53,208		44,340[i]	50,292[f]	12 Feb 2(
2011[c]	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		91,638[i]		
2012[d]	Comp	2013-2015	11 Feb 2013		97,278	97,278		
	Vol	2013-2015	11 Feb 2013		97,278	97,278		
	Mat	2013-2015	11 Feb 2013		194,556	32,424[i]		

Comp = Compulsory.

Vol = Voluntary.

Mat = Matching.

DAB = Deferred annual bonus plan.

[a] Since 2010, vesting of the deferred shares has been subject to a safety and environmental sustainability hurdle, and this will continue. If the committee assesses that there has been a material deterioration in safety and environmental performance, or there have been major incidents, either of which reveal underlying weaknesses in safety and environmental management, then it may conclude that shares should vest only in part, or not at all. In reaching its conclusion, the committee will obtain advice from the SEEAC. There is no identified minimum vesting threshold level.

[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] The face value has been calculated using the market price of ordinary shares on 8 March 2012 of £4.94.

[d] The market price at closing of ordinary shares on 11 February 2013 was £4.55 and for ADSs was $43.01 and on 12 February 2014 was £4.87 and for ADSs was $48.38. The sterling value has been used to calculate the face value.

[e] 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.

[f] The market price of each share used to determine the total value at vesting on the vesting dates of 15 January 2013, 9 January 2014 and 12 February 2014 were £4.58, £4.97 and £4.90 respectively and for ADSs on 12 February 2014 was $48.41.

[h] The face value has been calculated using the market price of ordinary shares on 15 March 2012 of £4.93.

[i] All deferred and matched shares have been prorated to reflect actual service during the performance period and these figures have been used to calculate the face value.

Table of Contents

Performance shares (audited)

		Share element interests				Interests vested in 2013 and		
		Potential maximum performance shares[a]				Number of ordinary shares		F
Performance period	Date of award of performance shares	At 1 Jan 2013	Awarded 2013	At 31 Dec 2013	Awarded 2014	vested	Vesting date	
2010-2012	09 Feb 2010	581,082				0		
2011-2013	09 Mar 2011	1,330,332		1,330,332		596,028[c]	March 2014	
2012-2014[d]	08 Mar 2012	1,343,712		1,343,712				
2013-2015[d]	11 Feb 2013		1,384,026	1,384,026				
2014-2016[d]	12 Feb 2014				1,304,922			
2008-2013[e]	13 Feb 2008	133,452				145,489	07 Feb 2013	
2010-2012	09 Feb 2010	656,813				0		
2011-2013	09 Mar 2011	623,025		623,025		283,920	March 2014	
2012-2014[d]	08 Mar 2012	660,633		660,633				
2013-2015[d]	11 Feb 2013		694,688	694,688				
2014-2016[d]	12 Feb 2014				660,128			
2010-2012[f]	15 Mar 2010	60,000				65,414[c]	15 Jan 2013	
2011-2013[f]	14 Mar 2011	67,500		67,500		76,726[c]	09 Jan 2014	
2010-2012[g]	15 Mar 2010	22,500				0		
2011-2013[g]	14 Mar 2011	22,500		22,500		25,824[c]	06 Feb 2014	
2012-2014[d]	08 Mar 2012	624,434		624,434				
2013-2015[d]	11 Feb 2013		637,413	637,413				
2014-2016[d]	12 Feb 2014				605,544			
cutive directors								
2010-2012	09 Feb 2010	303,948[h]				0		
2010-2012	09 Feb 2010	218,938[h]				0		
2010-2012	09 Feb 2010	801,894				0		
2011-2013	09 Mar 2011	785,394		654,498[h]		293,232[c]	March 2014	
2012-2014[d]	08 Mar 2012	828,936		414,468[h]				
2013-2015[d]	11 Feb 2013		853,650	142,278[h]				

[a] 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 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, 2013-2015 and 2014-2016 plans, performance conditions are measured one-third on TSR against ExxonMobil, Shell, Total and Chevron; one-third on operating cash flow; and one-third on a balanced scorecard of strategic imperatives. Each performance period ends on 31 December of the third year. There is no identified overall minimum vesting threshold level but to comply with UK regulations a value of 30%, which is conditional on the TSR, reserves replacement ratio and one of the strategic imperatives reaching the minimum threshold, has been calculated.

[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] 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. The market price of each share at the vesting date of 15 January 2013 was £4.58, at 9 January 2014 was £4.97 and at 6 February 2014 was £4.77. For the assumed vestings dated March 2014 a price of £4.69 per ordinary share and $45.52 per ADS has been used. These are the average prices from the fourth quarter of 2013.

[d] The market price at closing of ordinary shares on 8 March 2012 was £4.94, on 11 February 2013 was £4.55 and for ADSs was $43.01 and on 12 February 2014 was £4.87 and for ADSs was $48.38. The sterling value has been used to calculate the face value.

[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 element have been pro-rated to reflect actual service during the performance period and these figures have been used to calculate the face value as appropriate.

Share interests in share option plans (audited)

on type	At 1 Jan 2013	Granted	Exercised	At 31 Dec 2013	Option price	Market price at date of exercise	Date from which first exercisable
BP SOP	17,835		17,835[b]		$38.10	$43.99	17 Feb 2006
SAYE	605		605[c]		£4.20	£4.54	01 Sep 2012
SAYE	3,017			3,017	£3.68		01 Sep 2016
SAYE	797			797	£3.16		01 Sep 2015
BP 2011	500,000			500,000	£3.72		07 Sep 2014
SAYE	4,191			4,191	£3.68		01 Sep 2016

The closing market prices of an ordinary share and of an ADS on 31 December 2013 were £4.88 and $48.61 respectively.

During 2013 the highest market prices were £4.93 and $48.61 respectively and the lowest market prices were £4.31 and $40.19 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.

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 all employee share scheme.

[a] Numbers shown are ADSs under option. One ADS is equivalent to six ordinary shares.
[b] Options exercised on 6 February 2013. Market price at closing for information. Shares were sold in tranches after the exercise of options at an average price of $43.62 per ADS.
[c] Options exercised on 13 February 2013. Market price at closing for information. Shares were retained after the exercise of options.

Table of Contents

(b) Non-executive directors

This section of the directors remuneration report completes the directors annual report on remuneration with details for non-executive directors.

There were no changes following the review of non-executive remuneration undertaken in 2012 which benchmarked the structure and fees of BP non-executive directors against the 10 largest companies by market capitalization in the FTSE100. In March 2013 it was agreed that the chairman s fee would be increased from 1 May 2013. There are no changes proposed to the implementation of the policy for non-executive directors and the chairman for 2014.

Fee structure

The table below shows the fee structure for non-executive directors from 1 May 2013:

	Fee level £ thousand
Chairman[a]	785
Senior independent director[b]	120
Board member	90
Audit, Gulf of Mexico, remuneration and SEEA chairmanship fees[c]	30
Committee membership fee[d]	20
Intercontinental travel allowance	5

[a] The chairman is 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 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.

The table below shows the fees paid for non-executive directors for the years ended 31 December 2012 and 31 December 2013:

2013 remuneration (audited)

	Total fees	
All fees in £ thousand	2013	2012
Carl-Henric Svanberg	773[a]	750
Paul Anderson	175	149

Admiral Frank Bowman	165	126
Antony Burgmans	145	120
Cynthia Carroll	120	98
George David[b]	185	135
Ian Davis	150	128
Professor Dame Ann Dowling[c]	140	97
Brendan Nelson	130	119
Phuthuma Nhleko	150	123
Andrew Shilston	150	125

[a] The chairman received a further £49,000 by way of taxable benefits.

[b] In addition, George David received £12,500 for chairing the BP technology advisory council until 1 July 2013.

[c] In addition, Professor Dowling received £25,000 for chairing and being a member of the BP technology advisory council and £3,000 for an ad hoc technology advisory council meeting fee.

Non-executive director interests

The figures below indicate and include all the beneficial and non-beneficial interests of each non-executive director of the company in shares of BP (or calculated equivalents) that have been disclosed to the company under the DTRs as at the applicable dates.

Current non-executive directors	Ordinary shares or equivalents at 1 Jan 2013	Ordinary shares or equivalents at 31 Dec 2013	Change from 31 Dec 2013 to 24 Feb 2014	Ordinary shares or equivalents total at 24 Feb 2014	Value of current shareholding	% of policy achieved
Carl-Henric Svanberg	988,077	1,039,276		1,039,276	£5,258,737	670
Paul Anderson	6,000[a]	30,000[a]		30,000[a]	$251,350	168
Admiral Frank Bowman	16,320[a]	16,320[a]		16,320[a]	$136,734	91
Antony Burgmans	10,156	10,156		10,156	£51,389	57
Cynthia Carroll	10,500[a]	10,500[a]		10,500[a]	$87,973	59
George David	579,000[a]	579,000[a]		579,000[a]	$4,851,055	3,241
Ian Davis	10,866	11,449		11,449	£57,932	64
Professor Dame Ann Dowling	11,630	22,320		22,320	£112,939	125
Brendan Nelson	11,040	11,040		11,040	£55,862	62
Phuthuma Nhleko						0
Andrew Shilston	15,000	15,000		15,000	£75,900	63

[a] Held as ADSs.

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 on 1 October 2010. During 2013, 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 2013, he received 100,000 for this role.

Table of Contents

Directors remuneration policy

The following pages set out the remuneration policy for directors of BP p.l.c., which, if approved by shareholders at the AGM on 10 April 2014, will take effect from the date of that meeting.

The policy is divided into separate sections for executive and non-executive directors. The remuneration of the executive directors is set by the remuneration committee (the committee) under delegated powers from the board. The committee makes a recommendation to the board for the remuneration of the chairman. The remuneration of the non-executive directors is set by the board based on a recommendation from the chairman, the group chief executive and the company secretary.

(a) Executive directors

Introduction

The remuneration policy for the executive directors and the decisions of the remuneration committee have been consistently guided by six key principles. These principles were introduced more than 10 years ago and have been described in all remuneration reports to shareholders since then.

Key principles

The principles represent the overarching approach of the board and the committee to the remuneration of the executive directors.

Linked to strategy: A substantial proportion of executive director remuneration is linked to success in implementing the company s strategy.

Performance related: The major part of total remuneration varies with performance, with the largest elements being share based, further aligning with shareholders interests.

Long term: The structure of pay is designed to reflect the long-term nature of BP s business and the significance of safety and environmental risks.

Informed judgement: There are quantitative and qualitative assessments of performance with the remuneration committee making informed judgement within a framework approved by shareholders.

Fair treatment: Total overall pay takes account of both the external market and company conditions to achieve a balanced, fair outcome.

Shareholder engagement: The remuneration committee actively seeks to understand shareholder preferences and be transparent in explaining its policy and decisions.

The aim of this policy is to ensure that executive directors are remunerated in a way that reflects the company s long-term strategy. Consistent with this, a high proportion of directors total potential remuneration has been, and will be, strongly linked to the company s long-term performance.

Table of Contents

Flexibility, judgement and discretion

The committee is empowered to undertake quantitative and qualitative assessments of performance in reaching its decisions. This involves the use of judgement and discretion within a framework that is approved by, and transparent to, shareholders.

The committee considers that the powers of flexibility, judgement and discretion are critical to successful design and implementation of the remuneration policy. This approach is supported in the UK by the ABI s principles of remuneration and the GC100 and Investor Group s guidance on directors remuneration reporting.

In framing this policy, the committee has therefore taken care to ensure that these existing and important powers are continued in the future.

The committee considers that an effective remuneration policy needs to be sufficiently flexible to take account of future changes in the industry environment facing BP and in remuneration practice generally. The policy is therefore sufficiently flexible so that the committee can react to changed circumstances (for example in applying particular performance measures within schemes which may need to evolve with the strategy of the company), without the need for a specific shareholder approval.

The policy preserves the committee s long-standing power to exercise judgement in making a qualitative assessment in certain circumstances. For annual or long-term bonus awards a number of metrics are used. Many are numerical in nature and require a quantitative assessment. Some will be qualitative, for example the maintenance or improvement in the company s reputation. Here an impartial assessment will be required.

This policy sets out various areas where the committee has discretion, mainly where it is desirable to vary a formulaic outcome that would otherwise arise from the policy s implementation. The committee considers that the ability to exercise discretion, upwards or downwards, is important to ensure that a particular outcome is fair in light of the director s own performance and the company s overall performance and positioning under particular performance metrics. In accordance with UK regulations, areas where the remuneration policy provides for the exercise of discretion are identified in the report.

This policy sets out the areas where the committee wishes to have flexibility or use discretion in its implementation. Each year, the committee will report to shareholders on the use of these powers.

Key considerations

The committee considers a wide range of factors when developing the remuneration policy for executive directors. The competitive market for top executives both within the oil sector and broader industrial corporations provides an important context. The committee believes that it has a duty to shareholders to ensure that the company is competitive so as to attract and retain the high calibre executives required to lead the company.

The committee also considers employment conditions within the company when establishing and implementing policy for executive directors to ensure alignment of principles and approach. In particular the committee reviews the policy for the group leaders of around 500 top executives to ensure that policy for both groups is aligned and reflects consistent standards and approach.

Decisions regarding remuneration for employees outside the group leaders are the responsibility of the group chief executive. Employees are not consulted directly by the committee when making policy decisions although feedback from employee surveys provide views on a wide range of points including pay which are regularly reported to the board.

The committee has a long-standing and active programme of engaging with key shareholders that includes one-on-one meetings with them each year. This engagement programme complements the overall investor relations and board engagement efforts of the company, and focuses mainly on our largest shareholders and main proxy advisers. Feedback from shareholders on executive director remuneration forms an important component of the committee s considerations when establishing policy.

Implementation matters

This policy is a forward-looking document, but it is a requirement of the regulations that, if obligations under the company s previous remuneration policy are to remain in force, these must be stated and certain information must be provided. In view of the long-term nature of BP s remuneration structures including obligations under service contracts, pension arrangements, the executive directors incentive plan (EDIP) and other incentive awards a substantial number of pre-existing obligations will remain outstanding at the time that this policy is approved, including obligations that are grandfathered by virtue of being in force at 27 June 2012. It is the company s policy to honour in full any pre-existing obligations that have been entered into prior to the effective date of this policy.

Finally the new regulations require detailed information on performance measures and targets to be included in the report unless the directors consider that information to be commercially sensitive. The directors are committed to full and transparent disclosure to shareholders and will seek to provide the information wherever possible. However, the directors have determined that the current targets for short- and long-term incentives are commercially sensitive and should not be disclosed at the commencement of any relevant performance period as they believe this is not in the interests of the company. The directors will review such targets at the end of each relevant performance period and determine whether any target may be disclosed.

Executive directors incentive plan

The EDIP was first approved by shareholders in April 2000 and has since provided the umbrella framework for share based remuneration for executive directors. With the introduction of the new UK regulations on pay reporting, the prime shareholder approval for all elements of remuneration policy, including share based elements, will now be via the policy report. The EDIP will continue to provide the vehicle to implement the share based elements of policy that have been approved by shareholders, the EDIP will continue to require a separate shareholder approval under UK Listing Rules, and its renewal has been brought forward to the 2014 AGM to coincide with the approval of this remuneration policy. Given the duplication of the two regulatory regimes, the remuneration committee will ensure that any actions taken in future under the EDIP will be consistent with the policy approved by shareholders.

Table of Contents

Remuneration policy table

Note: Further information is set out in the accompanying notes which follow this table.

Table of Contents

Remuneration policy in more depth

Salary and benefits

At 1 January 2014, the annual salaries for executive directors were as follows: Bob Dudley $1,800,000, Iain Conn £774,000 and Dr Brian Gilvary £710,000.

Most components of total remuneration are determined as multiples of salary and so the committee reviews salaries, normally annually. These reviews consider both external competitiveness and internal consistency when determining if any increases should be applied.

Salaries are compared against other oil majors, but the committee also monitors market practice among European and US companies of a similar size, geographic spread and business dynamic to BP.

Salaries are normally set in the home currency of the executive director. The levels of increase for all our employees in relevant countries, as well as the profile of increases for group leaders, are reviewed and considered when assessing executive director salary increases.

The committee would expect annual increases to be in line with all employee increases in the UK and US, unless there are promotions or significant changes in responsibilities, in which case they would retain the flexibility to recognize these with appropriate salary increases but will be limited to within 2% of average increase for the group leaders.

The committee will make a balanced judgement of what, if any, increase should be applied to each executive director s salary. These decisions, and the reasons for them, form part of the annual report of remuneration.

Benefits and other emoluments

Executive directors are entitled to receive those benefits which are made available to employees generally in accordance with their applicable terms, for example sharesave plans, sickness policy, relocation assistance and maternity pay. Benefits are not pensionable.

In addition, executive directors may receive other benefits that are judged to be cost effective and prudent in terms of the individual s time and/or security. These include car-related benefits, security assistance, tax preparation assistance, insurance and medical benefits. The costs of these are treated as taxable benefits to the individuals and are included in the single figure table of the annual report on remuneration. The company would meet any tax charges arising in respect of benefits provided to directors that it considers relate to its business (for example security assistance).

The committee expects to maintain benefits at their current level for the duration of this policy but notes that the taxable value may fluctuate depending on, amongst other things, insurance premiums, and a director s personal circumstances.

Annual bonus

Operation

Highlights

150% of salary on target, 225% maximum.
Metrics focused on safety and operational risk,

and on value creation.
Details on performance measures will be explained each

year in annual report on remuneration.

Executive directors are eligible for an annual bonus (before any deferral) of 150% of salary at target and 225% at maximum. Bonuses for the group chief executive and the chief financial officer will be based entirely on group measures. Executive directors with large operating responsibilities may have up to 50% of their bonus based on their respective business segment, with the balance based on group measures.

The strategy provides the overall context for the company s key performance indicators and the focus for the annual plan. From this, measures and targets to reflect the key priorities of the business are selected at the start of the year for senior managers, including executive directors. Measures typically include a range of financial and operating ones as well as those relating to safety and the environment.

Where possible, the committee uses quantifiable, hard targets that can be factually measured and objectively assessed. Where it is appropriate to use qualitative measures, the information used to make assessments will be established at the start of or early in the year. Targets are set so that achieving plan levels of performance results in on-target bonus. For maximum levels, targets reflect performance levels that the committee judges are very stretching but nonetheless achievable.

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).

In addition to the specific bonus metrics, the committee also reviews the underlying performance of the group in light of the annual plan, competitors results and analysts reports, and seeks input from other committees on relevant aspects. When appropriate, the committee may make adjustments, up or down, 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 a number of years, reflecting the changing circumstances of the company during the period. The following chart shows the average annual bonus result (before any deferral) relative to an on-target level for executive directors.

History of annual bonus results

Performance measures

The measures used to determine bonus results will derive from the annual plan and support the strategic priorities of safety and operational risk (S&OR) management and reinforcing value creation.

The committee determines specific measures, weightings and targets each year to reflect the group s strategy, key performance indicators (KPIs) and the priorities in the annual plan. These measures will be reported each year in the annual report on remuneration.

For safety and operational risk management the measures may include established ones such as loss of primary containment, tier 1 process safety events, recordable injury frequency, and/or days away from work frequency. The measures selected will typically track both process and personal safety and give an overall perspective on performance. The committee will also seek the input of the safety, ethics and environmental 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.

Value creation will form the principal measures and include both financial and operating metrics that track performance relative to value creation. Financial measures for value creation may include operating cash flow, underlying replacement cost profit, and cost management or other similar measures tracking the financial outcome of the company s pursuit of strategic goals. Additional operating metrics may include major project delivery, Upstream unplanned deferrals, and Downstream net income per barrel or other similar measures that track key operating aspects of the strategy.

Where segment metrics are applied, they will typically include specific safety metrics for the segment as well as value metrics such as availability, efficiency, profitability and major project delivery.

Table of Contents

Deferred bonus

The structure of deferred bonus, awarded in shares, focuses on long-term alignment with shareholder interests and reinforces the critical importance of maintaining high safety and environmental standards. It translates the outcome of a portion of the annual bonus into a long-term plan with

additional performance hurdles. As shown below, the deferred bonus is converted to shares, matched and deferred for three years. Half the total that vests will then normally have an additional three-year retention period before release.

Operation

Highlights
A third mandatory and up to a third voluntary deferral.
Converted to shares, matched one-for-one and deferred for three years.
Vesting of all conditional on safety and environmental sustainability hurdle.
Matched shares subject to additional three-year retention period post vesting.

A third of the annual bonus is required to be deferred for three years. Under the rules of the plan, the average share price over the three days following the announcement of full-year results is used to determine the number of shares awarded. Deferred shares are matched on a one-for-one basis.

Executive directors may elect, with the committee s agreement, to take up to a further third of their annual bonus in shares, which will vest and will qualify for matching on the same basis as above.

Both deferred and matched shares vest after three years depending on the committee s 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 reinvested dividends on those shares.

Beginning with the 2013 bonus deferral, matched shares that vest (half of the total that vests) will normally be subject to a compulsory retention period of a further three years. Sufficient shares may be sold to discharge tax liabilities at the vesting date.

Performance measures

The safety and environmental sustainability hurdle, in place since 2010, will continue to be applied to all deferred shares. If the committee assesses that there has been a material deterioration in safety and environmental metrics, or there have been major incidents either of which reveal underlying weaknesses in safety and environmental management, then it may conclude that shares 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:

High standards in this area are an important priority of BP s strategy.

Maintaining safety and environmental standards over the long term is a good qualitative reflection of the sustainability of the business.

This non-financial hurdle complements the financial and operational performance conditions applicable to performance share awards.

Table of Contents

Performance shares

The performance share element reflects the committee s policy that a large proportion of remuneration is tied to long-term performance. This three-year performance period, combined with a further three-year

retention period for those shares that vest, creates a six-year incentive plan designed to ensure executive interests are aligned with those of shareholders.

Operation

Highlights

Shares awarded to five and a half times salary for the group chief executive and four times for other executive directors.

Three-year performance period.

Performance measures reflect strategy and KPIs.

Three-year retention period for those shares that vest.

Performance shares may be awarded conditionally at the start of each year to a value of up to five and a half times salary for the group chief executive and up to four times salary for the other executive directors (the maximum allowed under the EDIP). Under the rules of the EDIP, the average share price over the final quarter before the start of the performance period is used to determine the number of shares awarded. Performance shares will only vest to the extent that performance conditions are met.

Where shares vest, the executive director will receive additional shares representing the value of the reinvested 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.

A history of vesting of the share element is shown below, reflecting both demanding performance conditions and poor company performance during this period.

History of performance share vesting

Performance measures

Performance measures will be aligned to BP s strategy that focuses on value creation and reinforcing safety and operational risk management. Vesting of a portion of shares will be based on our total shareholder return (TSR) compared to other oil majors, reflecting the central importance of restoring and maintaining the value of the company. A further portion will be based on the operating cash flow of the company, reflecting a central element of value creation. The final portion will be based on a set of strategic imperatives such as reserves replacement ratio, S&OR management, and major project delivery.

For the TSR and the reserves replacement ratio measures, the comparator group will continue to consist of ExxonMobil, Shell, Total and Chevron. This group can be altered by the committee 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.

TSR will be calculated by taking the share price performance over the three-year performance 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 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%, 80% and 25% respectively, for performance equivalent to first, second and third place. No shares will vest for fourth or fifth place.

Operating cash flow has been identified as a core measure of strategic performance of the company. Targets will reflect agreed plans and normal operating assumptions.

The committee will determine the weightings, specific measures and targets for each year to reflect the strategic priorities for that year and the committee s judgement of where the focus should be for the upcoming period. These will be explained in the annual report on remuneration.

The committee considers that a combination of quantitative and qualitative measures reflects the long-term value creation priorities and the factors underpinning business sustainability.

The committee may exercise its judgement, in a reasonable and informed manner, to adjust vesting levels upwards or downwards if it concludes that this approach does not reflect the reality of the health and performance of the business relative to its peers. In addition the committee will review whether the level of vesting is consistent with shareholder interests. Any adjustments are explained in the annual report on remuneration following vesting, in line with its commitment to transparency.

Table of Contents

Pension

Executive directors are eligible to participate in the pension schemes that apply in their home country and which follow the national norms for structure and levels.

US executive directors

Highlights
Defined benefit core schemes.
Annual accrual of 1.3% of average annual earnings generally provides overall benefit.
Average earnings include salary and bonus.

Pension benefits in the US are provided through a combination of tax-qualified and non-qualified benefit plans, consistent with applicable US tax regulations.

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 formulae for certain employees of companies acquired by BP (including Amoco and Arco) who participated in these predecessor company pension plans.

The TNK-BP supplemental retirement plan is a lump sum benefit based on the same calculation as the benefit under the US pension plan but reflecting 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 supplemental 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 Amoco formula includes a reduction of 5% per year if taken before age 60.

The BP supplemental executive retirement benefit plan (SERB) is a supplemental plan 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.

UK executive directors

Highlights
Defined benefit core schemes.
One sixtieth annual accrual to a maximum

of two-thirds final salary.
35% cash supplement in lieu of future service

accrual for those in excess of UK government limits.

UK executive directors are members of the BP pension scheme in respect of service prior to 1 April 2011. The core benefits under this scheme are non-contributory. The benefits include a pension accrual of one sixtieth 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, participants may receive 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 participants ceased pension accrual for future service to remain within the new annual allowance. For 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 the arrangements.

The rules of the BP pension scheme were amended in 2006 to reflect the normal retirement age of 65. Prior to 1 December 2006, scheme members could retire on or after age 60 without reduction.

Special early retirement terms apply to executives in service on 1 December 2006. If they retire between 60 and 65, they are entitled to an immediate unreduced pension. If they retire 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; however 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 this, an individual leaving in circumstances of total incapacity is entitled to an immediate unreduced pension as from their leaving date.

Table of Contents

Scenario charts

The total remuneration opportunity for executive directors is strongly performance based and weighted to the long term. The charts below provide scenarios for the total remuneration of executive directors at different levels of performance and are calculated as prescribed in UK regulations. The fixed component in each chart includes current salary, taxable benefits and pension. The annual component reflects cash bonus, and in the case of Bob Dudley the pension accruing on his bonus. The long term includes both the deferred bonus and the performance shares. Detailed calculation assumptions are noted to the right of the charts.

Calculation assumptions

Minimum

Fixed components only

Current salary and taxable benefits.

Pension value of one year s service using current salary for US and cash in lieu for UK.
UK 35% x salary.
US 1.3% x salary x 20.

Target

Fixed

Current salary and taxable benefits.

Pension value of one year s service using current salary for US and cash in lieu for UK.
UK 35% x salary.
US 1.3% x salary x 20.

Annual

Cash bonus reflecting on-target level of 150% of salary of which two thirds are paid in cash.

For Bob Dudley, pension value of one year s service based on target bonus times 20 (1.3% x 150% x salary x 20).

Long term

Deferred bonus reflecting one third of target bonus of 150% of salary and one-for-one match.

Performance shares that vest to half maximum amounting to 2.75 times salary for Bob Dudley and two times salary for Iain Conn and Dr Brian Gilvary.

Maximum

Fixed

Current salary and taxable benefits.

Pension value of one year s service using current salary for US and cash in lieu for UK.
UK 35% x salary.
US 1.3% x salary x 20.

Annual

Cash bonus reflecting maximum of 225% of salary of which one third is paid in cash.

For Bob Dudley, pension value of one year s service based on maximum bonus times 20 (1.3% x 225% x salary x 20).

Long term

Deferred bonus reflecting two thirds of maximum bonus of 225% of salary and one-for-one match.

Performance shares that fully vest amounting to five and a half times salary for Bob Dudley and four times salary for Iain Conn and Dr Brian Gilvary.

Table of Contents

Recruitment

The committee expects any new executive directors to be engaged on terms that are consistent with the policy as described on the preceding pages. The committee recognizes that it cannot always predict accurately the circumstances in which any new directors may be recruited. The committee may determine that it is in the interests of the company and shareholders to secure the services of a particular individual which may require the committee to take account of the terms of that individual s existing employment and/or their personal circumstances. Accordingly, the committee will ensure that:

- Salary level of any new director is competitive relative to the peer group.
- Variable remuneration will be awarded within the parameters outlined on pages 98-99, save that the committee may provide that an initial award under the EDIP (within the salary multiple limits on page 98) is subject to a requirement of continued service over a specified period, rather than a corporate performance condition.
- Where an existing employee of BP is promoted to the board, the company will honour all existing contractual commitments including any outstanding share awards or pension entitlements.
- Where an individual is relocating in order to take up the role, the company may provide certain one-off benefits such as reasonable relocation expenses, accommodation for a period following appointment and assistance with visa applications or other immigration issues and ongoing arrangements such as tax equalization, annual flights home, and housing allowance.
- Where an individual would be forfeiting valuable remuneration in order to join the company, the committee may award appropriate compensation. The committee would require reasonable evidence of the nature and value of any forfeited award and would, to the extent practicable, ensure any compensation was no more valuable than the forfeited award and that it was paid in the form of shares in the company.

The committee would expect any new recruit to participate in the company pension and benefit schemes that are open to senior employees in his home country but would have due regard to the recruit s existing arrangements and market norms.

In making any decision on any aspect of the remuneration package for a new recruit, the committee would balance shareholder expectations, current best practice and the requirements of any new recruit and would strive not to pay more than is necessary to achieve the recruitment. The committee would give full details of the terms of the package of any new recruit in the next remuneration report.

Service contracts

Summary details of each executive director s service agreement are as follows:

	Service agreement date	Salary as at 1 Jan 2014
Bob Dudley	6 Apr 2009	$1,800,000
Iain Conn	22 Jul 2004	£774,000
Dr Brian Gilvary	22 Feb 2012	£710,000

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 2009, which has been further extended to 15 April 2019. His secondment can be terminated with one month s notice by either party and terminates automatically on the termination of his service agreement. 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 103.

Each executive director is entitled to the following contractual benefits:

A company car and chauffeur 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 and 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 deferred bonus and performance share plans as described on pages 100, 101 and 102 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.

Where appropriate the company may also meet a director s reasonable legal expenses in connection with either his appointment or termination of his appointment.

The committee considers that its policy on termination payments arising from the contractual provisions summarized above provides an appropriate degree of protection to the director in the event of termination and is consistent with UK market practice.

Exit payments

Should it become necessary to terminate an executive director s employment, and therefore to determine a termination payment, the committee s policy would be as follows:

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, taking into account 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 101-102 of this report). Any such determination will be made in accordance with the rules of the EDIP, as approved by shareholders.

Table of Contents

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 mainly relates 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.

A shorter vesting period for any share awards may apply on change of control.

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. Details of appointments during 2013 are shown below.

Director	Appointee company	Additional position held at appointee company	Total fees
Bob Dudley[a]	Rosneft	Director	0
Iain Conn	Rolls-Royce plc	Senior independent director and chairman of	£82,000

		the ethics committee	
Dr Byron Grote[b]	Unilever	Audit committee member	Unilever PLC £19,375 Unilever NV 22,990

[a] Bob Dudley holds this appointment as a result of the company s shareholding in Rosneft.
[b] On retirement at 11 April 2013.

Table of Contents

(b) Non-executive directors

This section of the directors   remuneration report describes the separate policies of the BP board for the remuneration of the chairman and the non-executive directors (NEDs).

Key principles

The principles which underpin the board   s policies for the remuneration of the chairman and the NEDs are as follows:

- Remuneration should be sufficient to attract, motivate and retain world-class non-executive talent.
- Remuneration practice should be consistent with recognized best practice standards for chairman and NED remuneration.
- The aggregate annual remuneration payable to the chairman and NEDs is determined by shareholder resolution in accordance with the company   s Articles of Association. The aggregate limit will be increased to £5 million if resolution 20 at the 2014 AGM is duly passed.
- NEDs should not receive share options, bonuses or retirement benefits from the company.
- NEDs are encouraged to establish a holding in BP shares of the equivalent value of one year   s base fee.

NEDs are supported through the company secretary   s office. This support includes assistance with travel and transport, security advice (when needed) and administrative services.

NEDs 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.

Board remuneration policy for the chairman

The chairman is non-executive and, in accordance with the Governance Code, independent on appointment. The quantum and structure of the chairman   s remuneration is set by the board based upon a recommendation from the remuneration committee. The chairman is not involved in setting his own remuneration.

This policy reflects the approach adopted by the board over the years and which has previously been described to shareholders.

The maximum remuneration for non-executive directors is set in accordance with the Articles of Association.

Table of Contents

Board remuneration policy for non-executive directors

The maximum remuneration for non-executive directors is set in accordance with the Articles of Association.

This directors remuneration report was approved by the board and signed on its behalf by David J Jackson, company secretary on 6 March 2014.

Table of Contents

Table of Contents

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, although the board has reviewed the exposure the group has to risk within joint arrangements.

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, corporate activities 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 2013, 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 2014 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 the design and operation of elements of BP s system of internal control over significant risks arising in the categories of strategic and commercial, 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 page 74). 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, re-appointment 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 page 74). Mr 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 2013 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 2013 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 2013 has been audited by Ernst & Young, an independent registered public accounting firm, as stated in their report appearing on page 121 of *BP Annual Report and Form 20-F 2013.*

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.

Table of Contents

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 arrangements (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 37 and Audit committee report on page 76 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 279.

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.

The Articles of Association may be amended by a special resolution.

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. A director may be removed by BP as provided for by applicable law and shall vacate office in certain circumstances as set out in the Articles of Association. 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.

Table of Contents

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.

Table of Contents

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 113 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.

Table of Contents

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Table of Contents

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Table of Contents

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 of 31 December 2013, 31 December 2012 and 1 January 2012, 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 2013. 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 2013, 31 December 2012 and 1 January 2012 and the group results of its operations and its cash flows for each of the three years in the period ended 31 December 2013, 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 Note 2 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.

As discussed in Note 1 to the consolidated financial statements, the group has changed its accounting policies for employee benefits and interests in joint arrangements, including related disclosures, as a result of adopting new and revised International Financial Reporting Standards.

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 of 31 December 2013, 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 2014 expressed an unqualified opinion.

/s/ Ernst & Young LLP

London, England

6 March 2014

Table of Contents

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 of 31 December 2013, 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 111. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, BP p.l.c. maintained, in all material respects, effective internal control over financial reporting as of 31 December 2013, 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 of 31 December 2013 and 2012, 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 2013, and our report dated 6 March 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

London, England

6 March 2014

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 6 March 2014, 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 2013 in the following Registration Statements:

Registration Statement on Form F-3 (File No. 333-179953) 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

London, England

6 March 2014

Table of Contents

Group income statement

For the year ended 31 December $ million

	Note	2013	2012[a]	2011[a]
Sales and other operating revenues	7	**379,136**	375,765	375,713
Earnings from joint ventures after interest and tax	17	**447**	260	767
Earnings from associates after interest and tax	18	**2,742**	3,675	4,916
Interest and other income	8	**777**	1,677	688
Gains on sale of businesses and fixed assets	5	**13,115**	6,697	4,132
Total revenues and other income		**396,217**	388,074	386,216
Purchases	21	**298,351**	292,774	285,133
Production and manufacturing expenses[b]		**27,527**	33,926	24,163
Production and similar taxes	7	**7,047**	8,158	8,280
Depreciation, depletion and amortization	7	**13,510**	12,687	11,357
Impairment and losses on sale of businesses and fixed assets	5	**1,961**	6,275	2,058
Exploration expense	10	**3,441**	1,475	1,520
Distribution and administration expenses		**13,070**	13,357	13,958
Fair value gain on embedded derivatives	26	**(459)**	(347)	(68)
Profit before interest and taxation		**31,769**	19,769	39,815
Finance costs[b]	8	**1,068**	1,072	1,187
Net finance expense relating to pensions and other post-retirement benefits	30	**480**	566	400
Profit before taxation		**30,221**	18,131	38,228
Taxation[b]	11	**6,463**	6,880	12,619
Profit for the year		**23,758**	11,251	25,609
Attributable to				
BP shareholders	32	**23,451**	11,017	25,212
Non-controlling interests	32	**307**	234	397
		23,758	11,251	25,609
Earnings per share cents				
Profit for the year attributable to BP shareholders				
Basic	13	**123.87**	57.89	133.35
Diluted	13	**123.12**	57.50	131.74

[a] See Note 1 for information on the restatement of comparative amounts as a result of the adoption of IFRS 11 Joint Arrangements and the amended IAS 19 Employee Benefits .

[b] See Note 2 for information on the impact of the Gulf of Mexico oil spill on these income statement line items.

Table of Contents

Group statement of comprehensive income

For the year ended 31 December	Note	2013	2012[a]	$ million 2011[a]
Profit for the year		**23,758**	11,251	25,609
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**(1,608)**	485	(543)
Exchange gains (losses) on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**22**	(15)	19
Available-for-sale investments marked to market		**(172)**	306	(71)
Available-for-sale investments reclassified to the income statement		**(523)**	(1)	(3)
Cash flow hedges marked to market	26	**(2,000)**	1,466	44
Cash flow hedges reclassified to the income statement	26	**4**	62	(195)
Cash flow hedges reclassified to the balance sheet	26	**17**	19	(13)
Share of items relating to equity-accounted entities, net of tax		**(24)**	(39)	(39)
Income tax relating to items that may be reclassified	11,32	**147**	(170)	23
		(4,137)	2,113	(778)
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	30	**4,764**	(1,572)	(5,301)
Share of items relating to equity-accounted entities, net of tax		**2**	(6)	
Income tax relating to items that will not be reclassified	11,32	**(1,521)**	440	1,467
		3,245	(1,138)	(3,834)
Other comprehensive income		**(892)**	975	(4,612)
Total comprehensive income		**22,866**	12,226	20,997
Attributable to				
BP shareholders	32	**22,574**	11,988	20,613
Non-controlling interests	32	**292**	238	384
		22,866	12,226	20,997

[a] See Note 1 for information on the restatement of comparative amounts as a result of the adoption of IFRS 11 Joint Arrangements , the amended IAS 19 Employee Benefits and the amended IAS 1 Presentation of Financial Statements .

Group statement of changes in equity[a b]

$ million

	Share capital and capital reserves	Own shares and treasury shares	Foreign currency translation reserve	Fair value reserve	Share-based payment reserve	Profit and loss account	BP shareholders equity	Non-controlling interests	Total equity

At 1 January 2013	43,513	(21,054)	5,128	1,775	1,608	87,576	118,546	1,206	119,752
Profit for the year						23,451	23,451	307	23,758
Other comprehensive income			(1,603)	(2,470)		3,196	(877)	(15)	(892)
Total comprehensive income			(1,603)	(2,470)		26,647	22,574	292	22,866
Dividends						(5,441)	(5,441)	(469)	(5,910)
Repurchases of ordinary share capital						(6,923)	(6,923)		(6,923)
Share-based payments, net of tax	143	83			97	150	473		473
Share of equity-accounted entities changes in equity, net of tax						73	73		73
Transactions involving non-controlling interests								76	76
At 31 December 2013	43,656	(20,971)	3,525	(695)	1,705	102,082	129,302	1,105	130,407
At 1 January 2012	43,454	(21,323)	4,509	267	1,582	83,079	111,568	1,017	112,585
Profit for the year						11,017	11,017	234	11,251
Other comprehensive income			619	1,508		(1,156)	971	4	975
Total comprehensive income			619	1,508		9,861	11,988	238	12,226
Dividends						(5,294)	(5,294)	(82)	(5,376)
Share-based payments, net of tax	59	269			26	(70)	284		284
Transactions involving non-controlling interests								33	33
At 31 December 2012	43,513	(21,054)	5,128	1,775	1,608	87,576	118,546	1,206	119,752
At 1 January 2011	43,448	(21,211)	5,036	469	1,586	65,754	95,082	904	95,986
Profit for the year						25,212	25,212	397	25,609
Other comprehensive income			(527)	(202)		(3,870)	(4,599)	(13)	(4,612)
			(527)	(202)		21,342	20,613	384	20,997

Total comprehensive income									
Dividends						(4,072)	(4,072)	(245)	(4,317)
Share-based payments, net of tax	6	(112)			(4)	102	(8)		(8)
Transactions involving non-controlling interests						(47)	(47)	(26)	(73)
At 31 December 2011	43,454	(21,323)	4,509	267	1,582	83,079	111,568	1,017	112,585

[a] See Note 32 for further information.

[b] See Note 1 for information on the restatement of comparative amounts as a result of the adoption of IFRS 11 Joint Arrangements and the amended IAS 19 Employee Benefits .

Table of Contents

Group balance sheet

$ million

	Note	**31 December 2013**	31 December 2012[a]	1 January 2012[a]
Non-current assets				
Property, plant and equipment	14	**133,690**	125,331	123,431
Goodwill	15	**12,181**	12,190	12,429
Intangible assets	16	**22,039**	24,632	21,653
Investments in joint ventures	17	**9,199**	8,614	8,303
Investments in associates	18	**16,636**	2,998	13,291
Other investments	20	**1,565**	2,704	2,635
Fixed assets		**195,310**	176,469	181,742
Loans		**763**	642	824
Trade and other receivables	22	**5,985**	5,961	5,738
Derivative financial instruments	26	**3,509**	4,294	5,038
Prepayments		**922**	830	739
Deferred tax assets	11	**985**	874	611
Defined benefit pension plan surpluses	30	**1,376**	12	17
		208,850	189,082	194,709
Current assets				
Loans		**216**	247	244
Inventories	21	**29,231**	28,203	26,073
Trade and other receivables	22	**39,831**	37,611	43,589
Derivative financial instruments	26	**2,675**	4,507	3,857
Prepayments		**1,388**	1,091	1,315
Current tax receivable		**512**	456	235
Other investments	20	**467**	319	288
Cash and cash equivalents	23	**22,520**	19,635	14,177
		96,840	92,069	89,778
Assets classified as held for sale	4		19,315	8,420
		96,840	111,384	98,198
Total assets		**305,690**	300,466	292,907
Current liabilities				
Trade and other payables	25	**47,159**	46,673	52,000
Derivative financial instruments	26	**2,322**	2,658	3,220
Accruals		**8,960**	6,875	6,016
Finance debt	27	**7,381**	10,033	9,039
Current tax payable		**1,945**	2,503	1,943
Provisions	29	**5,045**	7,587	11,238
		72,812	76,329	83,456
Liabilities directly associated with assets classified as held for sale	4		846	538
		72,812	77,175	83,994
Non-current liabilities				

Other payables	25	**4,756**	2,292	3,214
Derivative financial instruments	26	**2,225**	2,723	3,773
Accruals		**547**	491	400
Finance debt	27	**40,811**	38,767	35,169
Deferred tax liabilities	11	**17,439**	15,243	15,220
Provisions	29	**26,915**	30,396	26,462
Defined benefit pension plan and other post-retirement benefit plan deficits	30	**9,778**	13,627	12,090
		102,471	103,539	96,328
Total liabilities		**175,283**	180,714	180,322
Net assets		**130,407**	119,752	112,585
Equity				
BP shareholders equity	32	**129,302**	118,546	111,568
Non-controlling interests	32	**1,105**	1,206	1,017
Total equity	32	**130,407**	119,752	112,585

[a] See Note 1 for information on the restatement of comparative amounts as a result of the adoption of IFRS 11 Joint Arrangements and the amended IAS 19 Employee Benefits .

C-H Svanberg Chairman

R W Dudley Group Chief Executive

6 March 2014

Table of Contents

Group cash flow statement

For the year ended 31 December				$ million
	Note	**2013**	2012[a]	2011[a]
Operating activities				
Profit before taxation[b]		**30,221**	18,131	38,228
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	10	**2,710**	745	1,024
Depreciation, depletion and amortization	7	**13,510**	12,687	11,357
Impairment and (gain) loss on sale of businesses and fixed assets	5	**(11,154)**	(422)	(2,074)
Earnings from joint ventures and associates		**(3,189)**	(3,935)	(5,683)
Dividends received from joint ventures and associates		**1,391**	1,763	5,040
Interest receivable		**(314)**	(379)	(284)
Interest received		**173**	175	210
Finance costs	8	**1,068**	1,072	1,187
Interest paid		**(1,084)**	(1,166)	(1,125)
Net finance expense relating to pensions and other post-retirement benefits	30	**480**	566	400
Share-based payments		**297**	156	(88)
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	30	**(920)**	(858)	(1,003)
Net charge for provisions, less payments		**1,061**	5,338	2,988
(Increase) decrease in inventories		**(1,193)**	(1,720)	(4,079)
(Increase) decrease in other current and non-current assets		**(2,718)**	2,933	(9,860)
Increase (decrease) in other current and non-current liabilities		**(2,932)**	(8,125)	(5,957)
Income taxes paid		**(6,307)**	(6,482)	(8,063)
Net cash provided by operating activities		**21,100**	20,479	22,218
Investing activities				
Capital expenditure		**(24,520)**	(23,222)	(17,978)
Acquisitions, net of cash acquired	3	**(67)**	(116)	(10,909)
Investment in joint ventures		**(451)**	(1,526)	(855)
Investment in associates		**(4,994)**	(54)	(55)
Proceeds from disposals of fixed assets	5	**18,115**	9,992	3,504
Proceeds from disposals of businesses, net of cash disposed[c]	5	**3,884**	1,606	(663)
Proceeds from loan repayments		**178**	245	203
Net cash used in investing activities		**(7,855)**	(13,075)	(26,753)
Financing activities				
Net issue (repurchase) of shares		**(5,358)**	122	74
Proceeds from long-term financing		**8,814**	11,087	11,600
Repayments of long-term financing		**(5,959)**	(7,177)	(9,102)
Net increase (decrease) in short-term debt		**(2,019)**	(666)	2,222
Net increase (decrease) in non-controlling interests		**32**		
Dividends paid				
BP shareholders	12	**(5,441)**	(5,294)	(4,072)

Non-controlling interests	**(469)**	(82)	(245)
Net cash provided by (used in) financing activities	**(10,400)**	(2,010)	477
Currency translation differences relating to cash and cash equivalents	**40**	64	(493)
Increase (decrease) in cash and cash equivalents	**2,885**	5,458	(4,551)
Cash and cash equivalents at beginning of year	**19,635**	14,177	18,728
Cash and cash equivalents at end of year	**22,520**	19,635	14,177

[a] See Note 1 for information on the restatement of comparative amounts as a result of the adoption of IFRS 11 Joint Arrangements and the amended IAS 19 Employee Benefits .

[b] 2012 included $709 million of dividends received from TNK-BP. See Note 6 for further information.

[c] 2011 included the repayment of a deposit received in advance of $3,530 million following the termination of an agreement in respect of the expected sale of our interest in Pan American Energy LLC.

Table of Contents

Notes on financial statements

Changes to the 2013 financial statements

BP aims for the highest standard of financial reporting and supports the initiatives of the UK Financial Reporting Council and the US Securities and Exchange Commission to improve understandability and transparency by cutting immaterial clutter from financial statements. We continually review the structure and content of our financial reports. For the 2013 financial statements, to increase their understandability and navigability, we have changed the grouping of certain notes, and have also sought to remove immaterial disclosures. In applying materiality to the financial statement disclosures, we consider both the amount and the nature of each item. The main changes compared with the financial statements included in the *BP Annual Report and Form 20-F 2012* are as follows:

Note 1 Significant accounting policies, judgements, estimates and assumptions this note includes the critical accounting estimates and judgements in boxed text following the relevant accounting policy. Last year this information was shown under Critical accounting policies in the Additional disclosures section of the Directors Report.
Note 2 Significant event Gulf of Mexico oil spill now contains all of our financial statement note disclosures in respect of the 2010 oil spill. Last year we also included information in the Provisions and Contingent liabilities notes to the financial statements.
Note 7 Segmental analysis now includes analysis of depreciation, depletion and amortization and production and similar taxes, previously provided in separate notes.
Note 8 Income statement analysis now combines a number of notes previously provided separately, simplifying the presentation while retaining materially the same content.
Note 15 Goodwill and impairment review of goodwill now contains the disclosures related to impairment testing of goodwill, which were provided in a separate note last year.
Note 19 Financial instruments and financial risk factors and Note 26 Derivative financial instruments have been rationalized to focus only on the material matters.
Note 38 Subsidiaries, joint arrangements and associates now lists only the most significant entities.
A separate share-based payment note is no longer presented. The share-based payment expense for the year is included in Note 33 Employee costs and numbers and information on the dilutive impact of employee share plans is included in Note 13 Earnings per ordinary share.

1. Significant accounting policies, judgements, estimates and assumptions

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 2013 were approved and signed by the group chief executive and chairman on 6 March 2014 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 and critical accounting judgements, estimates and assumptions 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 2013. The standards and interpretations adopted in the year, and the corresponding impact on the financial statements, are described further on page 137.

The accounting policies that follow have been consistently applied to all years presented. Where retrospective restatements were required as a result of the implementation of new accounting standards or changes to existing accounting standards, these have been applied to all comparative years presented.

Subsequent to releasing our unaudited fourth quarter and full year 2013 results announcement dated 4 February 2014, a minor amendment has been made to the split of the Upstream replacement cost profit before interest and tax between US and non-US. The amount reported for US for the year has been reduced by $0.2 billion to $3.1 billion and the amount reported for non-US has been increased by $0.2 billion to $28.9 billion. Similarly, amendments have also been made to the geographical analysis for revenues and capital expenditure and acquisitions. There was no impact on the group s profit or loss, net assets or cash flows 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.

Critical accounting policies: use of judgements, estimates and assumptions

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 and the disclosure of contingent 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 critical accounting judgements and estimates that could have a significant impact on the results of the group are set out in boxed text below, and should be read in conjunction with the information provided in the Notes on financial statements. The areas requiring the most significant judgement and estimation in the preparation of the consolidated financial statements are in relation to acquisitions of interests in other entities, oil and natural gas accounting, including the estimation of reserves, the recoverability of asset carrying values, derivative financial instruments, including the application of hedge accounting, provisions and contingencies, in particular provisions and contingencies related to the Gulf of Mexico oil spill, pensions and other post-retirement benefits and taxation.

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 of an investee exists when the investor 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. To have power over an investee, the investor must have existing rights that give it the current ability to direct the relevant activities of the investee. 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. Non-controlling interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to the group.

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

Interests in other entities

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 non-controlling interest in the acquiree. Non-controlling 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 non-controlling 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 the recoverable amount of the cash-generating unit to which the goodwill relates should be assessed. 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 joint ventures 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 the corresponding investment in joint ventures and associates, and any impairment of the investment is included within the group s share of earnings from joint ventures and associates.

Interests in joint arrangements

A joint arrangement is an arrangement of which two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

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. The results, assets and liabilities of a joint venture are incorporated in these financial statements using the equity method of accounting as described below.

Certain of the group s activities, particularly in the Upstream segment, are conducted through joint operations, which are joint arrangements whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. BP recognizes, on a line-by-line basis in the consolidated financial statements, its share of the assets, liabilities and expenses of these joint operations 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 joint operation.

Interests in associates

An associate is an entity over which the group has significant influence, through the power to participate in the financial and operating policy decisions of the investee, but which is not a subsidiary or a joint arrangement. The results, assets and liabilities of an associate are incorporated in these financial statements using the equity method of accounting as described below.

Significant estimate or judgement

Judgement is required in assessing the level of control obtained in a transaction to acquire an interest in another entity: depending upon the facts and circumstances in each case, BP may obtain control, joint control or significant influence over the entity or arrangement. Transactions which give BP control of a business are business combinations. If BP obtains joint control of an arrangement, judgement is also required to assess whether the arrangement is a joint operation or a joint venture. If BP has neither control nor joint control, it may be in a position to exercise significant influence over the entity, which is then accounted for as an associate.

Accounting for business combinations and acquisitions of investments in equity-accounted joint ventures and associates requires judgements and estimates to be made in order to determine the fair value of the consideration transferred, together with the fair values of the assets acquired and the liabilities assumed in a business combination, or the identifiable assets and liabilities of the equity-accounted entity at the acquisition date. 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 for business combinations.

At 31 December 2013, and since the transaction described in Note 6 concluded on 21 March 2013, BP owned 19.75% of the voting shares of OJSC Oil Company Rosneft (Rosneft), a Russian oil and gas company. The Russian federal government, through its investment company OJSC Rosneftegaz, owned 69.5% of the voting shares of Rosneft at 31 December 2013. BP uses the equity method of accounting for its investment in Rosneft because under IFRS it is considered to have significant influence. Significant influence is defined as the power to participate in the financial and operating policy decisions of the investee but is not control or joint control. IFRS identifies several indicators that may provide evidence of significant influence, including representation on the board of directors of the investee and participation in policy-making processes. BP s group chief executive, Bob Dudley, has been elected to the board of directors of Rosneft, he is a member of the Rosneft board s Strategic Planning Committee and he participated in Rosneft s steering committee to integrate TNK-BP. Furthermore, under the Rosneft Charter BP has the right to nominate a second director to Rosneft s nine-person board of directors for election at a general meeting of shareholders should it choose to do so in the future. In addition, BP holds the voting rights at general meetings of shareholders conferred by its 19.75% stake in Rosneft. In management s judgement, the group has significant influence over Rosneft, as defined by the relevant accounting standard, and the investment is therefore accounted for as an associate. BP s share of Rosneft s oil and natural gas reserves is included in the estimated net proved reserves of equity-accounted entities.

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

The equity method of accounting

Under the equity method, the investment in an equity-accounted entity (joint venture or associate) is carried on the balance sheet at cost plus post-acquisition changes in the group s share of net assets of the equity-accounted entity, less distributions received and less any impairment in value of the investment. Loans advanced to equity-accounted 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 equity-accounted entity, adjusted to account for depreciation, amortization and any impairment of the equity-accounted entity s assets based on their fair values at the date of acquisition.

The group statement of comprehensive income includes the group s share of the equity-accounted entity s other comprehensive income. The group s share of amounts recognized directly in equity by an equity-accounted entity is recognized directly in the group s statement of changes in equity.

Financial statements of equity-accounted entities are prepared for the same reporting year as the group. Where material differences arise, 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 equity-accounted entities are eliminated to the extent of the group s interest in the equity-accounted entity. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The group assesses investments in equity-accounted 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 over the joint venture or significant influence over the associate, or when the interest becomes classified as an asset held for sale.

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.

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. On 21 March 2013, the disposal of BP s investment in TNK-BP completed and BP increased its investment in Rosneft. See Note 6 for further information. BP s investment in Rosneft is reported as a separate operating segment since that date, reflecting the way in which the investment is managed.

A separate organization within the group deals with the ongoing response to the Gulf of Mexico oil spill. This organization reports directly to the group chief executive and its costs are excluded from the results of the operating segments. Under IFRS its costs are 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 IFRS. For further information see Note 7.

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, joint ventures 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, joint ventures 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, joint ventures 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, joint ventures 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, joint venture 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.

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 joint venture or 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.

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

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 natural 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.

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. 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.

Significant estimate or judgement

The determination of whether potentially economic oil and natural gas reserves have been discovered by an exploration well is usually made within one year after well completion, but can take longer, depending on the complexity of the geological structure. 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.

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 assets that necessarily take a substantial period of time to get ready for their intended use, 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.

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

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 depreciation of common facilities takes into account expenditures incurred to date, together with estimated future capital expenditure expected to be incurred relating to as yet undeveloped reserves expected to be processed through 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.

Significant estimate or judgement

The determination of the group s estimated oil and natural 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 natural 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 and regulatory requirements.

The estimation of oil and natural gas reserves and BP s process to manage reserves bookings is described in Supplementary information on oil and natural gas on page 200, which is unaudited. Details on BP s proved reserves and production compliance and governance processes are provided on page 245.

Estimates of oil and natural 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. 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.

The 2013 movements in proved reserves are reflected in the tables showing movements in oil and natural gas reserves by region in Supplementary information on oil and natural gas (unaudited) on page 200. Information on the carrying amounts of the group s oil and natural gas properties, together with the amounts recognized in the income statement as depreciation, depletion and amortization is contained in Note 10 and Note 7 respectively.

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 reserves 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. Fair value less costs to sell is identified as the price that would be received to sell the asset in an orderly transaction between market participants and does not reflect the effects of factors that may be specific to the entity and not applicable to entities in general.

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 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.

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

Significant estimate or judgement

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 2013, the group s long-term price assumptions were $90 per barrel for Brent and $6.50/mmBtu for Henry Hub (2012 $90 per barrel and $6.50/mmBtu). These long-term price assumptions are subject to periodic review and revision. 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.

For value in use calculations, 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 2013 the rates ranged from 12% to 14% nominal (2012 12% to 14% nominal). The discount rates applied in assessments of impairment are reassessed each year. In cases where fair value less costs to sell is used to determine the recoverable amount of an asset, where recent market transactions for the asset are not available for reference, accounting judgements are made about the assumptions market participants would use when pricing the asset. Fair value less costs to sell may be determined based on similar recent market transaction data or using discounted cash flow techniques. Where discounted cash flow analyses are used to calculate fair value less costs to sell, the discount rate used is the group s post-tax weighted average cost of capital.

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 $12.2 billion on its balance sheet (2012 $12.2 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 or natural gas prices or refining margins or marketing margins for an extended period, the group may need to recognize significant goodwill impairment charges.

The recoverability of intangible exploration and appraisal expenditure is covered under Oil and natural gas exploration, appraisal and development expenditure above.

Details of impairment charges recognized in the income statement are provided in Note 5 and details on the carrying amounts of assets are shown in Note 14, Note 15 and Note 16.

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.

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.

Financial assets

Financial assets are classified as loans and receivables; financial assets at fair value through profit or loss; derivatives designated as hedging instruments in an effective hedge; held-to-maturity financial assets; or as available-for-sale financial assets, 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. Cash and cash equivalents are 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.

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.

Held-to-maturity financial assets

Held-to-maturity financial assets are non-derivative financial assets with fixed or determinable payments and fixed maturity that management has the positive intention and ability to hold to maturity. They are measured at amortized cost using the effective interest method, less any impairment.

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

Available-for-sale financial assets

Available-for-sale financial assets are those non-derivative financial assets that are not classified as loans and receivables, financial assets at fair value through profit or loss, or held-to-maturity financial assets. After initial recognition, available-for-sale financial assets are measured at fair value, with gains or losses recognized within other comprehensive income, except for impairment losses, foreign exchange gains or losses and any changes in fair value arising from revised estimates of future cash flows, which are recognized in profit or loss.

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.

Significant estimate or judgement

Judgements are required in assessing the recoverability of overdue trade receivables, such as those in Egypt (see Note 19 for further details), 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. See Note 19 for information on overdue receivables.

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.

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.

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 the initial valuation are recognized immediately through 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 risk. 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.

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

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.

Significant estimate or judgement

The decision as to whether to apply hedge accounting or not can have a significant impact on the group s financial statements. Cash flow and fair value hedge accounting is applied to certain of the group s finance debt-related derivatives in the normal course of business. In addition, the financial statements reflect the application of cash flow hedge accounting to certain of the contracts signed in October 2012 for BP to sell its investment in TNK-BP and obtain an additional shareholding in Rosneft, which were accounted for as derivatives under IFRS. We applied all-in-one cash flow hedge accounting to the contracts to acquire shares in Rosneft, resulting in a pre-tax loss of $2,061 million being recognized in other comprehensive income for the year (2012 pre-tax gain of $1,410 million). See Note 26 for further information.

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.

Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The group categorizes assets and liabilities measured at fair value into one of three levels depending on the ability to observe inputs employed in their measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are inputs that are observable, either directly or indirectly, other than quoted prices included within level 1 for the asset or liability. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or BP s assumptions about pricing by market participants.

Significant estimate or judgement

In some cases the fair values of derivatives are estimated using internal models due to the absence of quoted prices or other observable, market-corroborated data. This applies to the group s longer-term derivative contracts and certain options, and to the forward contracts entered into in 2012 to purchase shares in Rosneft, as well as to the majority of the group s natural gas embedded contracts. 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 Note 26.

Offsetting of financial assets and liabilities

Financial assets and liabilities are presented gross in the balance sheet unless both of the following criteria are met: the group currently has a legally enforceable right to set off the recognized amounts; and the group intends to either settle on a net basis or realize the asset and settle the liability simultaneously. If both of the criteria are met, the amounts are set off and presented net.

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

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

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.

Significant estimate or judgement

Detailed information on the Gulf of Mexico oil spill, including the financial impacts, is provided in Note 2.

The provision recognized is the best reliable estimate of expenditures required to settle certain present obligations at the end of the reporting period, however there are future expenditures for which it is not possible to measure the obligation reliably. These are not provided for and are disclosed as contingent liabilities. Accounting judgement is required to identify when a provision can be measured reliably, which can be especially challenging when complex litigation activities are ongoing.

In addition, for those provisions which are recognized, there is significant estimation uncertainty about the amounts that will ultimately be paid, especially with regard to amounts payable under the Deepwater Horizon Court Supervised Settlement Program (DHCSSP). A provision is made for these costs when the amount can be measured reliably; this requires an analysis of claims received and processed and consideration of the status of ongoing legal activity.

The provision for penalties under the US Clean Water Act is based on the estimated civil penalty for strict liability. This provision is calculated based on estimates as to the volume of oil spilled, as well as the assumption that BP did not act with gross negligence or engage in wilful misconduct, each of which will eventually be determined by the court on the basis of the trial proceedings.

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; an obligation may also arise in cases where an asset has been sold but the subsequent owner is no longer able to fulfil its decommissioning obligations, for example due to bankruptcy. 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.

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 future revenues are capitalized. Expenditures that relate to an existing condition caused by past operations that do not contribute to 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.

Significant estimate or judgement

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. 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. If oil and natural gas production facilities and pipelines are sold to third parties and the subsequent owner is unable to meet their decommissioning obligations, judgement must be used to determine whether BP is then responsible for decommissioning, and if so the extent of that responsibility. 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 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.

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.

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 2013 was a real rate of 1.0% (2012 0.5%), which was based on long-dated government bonds.

Provisions and contingent liabilities in relation to the Gulf of Mexico oil spill are discussed in Note 2. Information about the group s other provisions is provided in Note 29. As further described in Note 35, 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.

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

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 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, where this is within the control of the employee is treated as a cancellation and expensed.

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, resulting from either a plan amendment or a curtailment (a reduction in future obligations as a result of a material reduction in the plan membership), are recognized immediately when the company becomes committed to a change.

Net interest expense relating to pensions and other post-retirement benefits represents the net change in present value of plan obligations and the value of plan assets resulting from the passage of time, and is determined by applying the discount rate to the present value of the benefit obligation at the start of the year, and to the fair value of plan assets at the start of the year, taking into account expected changes in the obligation or plan assets during the year. Net interest expense relating to pensions and other post-retirement benefits is recognized in the income statement.

Remeasurements of the net defined benefit liability or asset, comprising actuarial gains and losses, and the return on plan assets (excluding amounts included in net interest described above) are recognized within other comprehensive income in the period in which they occur.

The defined benefit pension plan surplus or deficit in the balance sheet comprises the total for each plan of the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds), less the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price.

Contributions to defined contribution plans are recognized in the income statement in the period in which they become payable.

Significant estimate or judgement

Accounting for pensions and other post-retirement benefits involves judgement about uncertain events, including estimated retirement dates, salary levels at retirement, mortality rates, determination of discount rates for measuring plan obligations and net interest expense, 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. The assumptions used may vary from year to year, which would affect future net income and net assets. Any differences between these assumptions and the actual outcome also affect future net income and net assets.

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, we adopted the revised version of IAS 19 Employee Benefits (see below for further information), and we now apply the same rate of return on plan assets as we use to discount our pension liabilities. The impact of this change on key financial statement line items is shown at the end of this note.

The pension and other post-retirement benefit assumptions at 31 December 2013, 2012 and 2011 are provided in Note 30.

The 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 Note 30.

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 Note 30.

Income taxes

Income tax expense represents the sum of current tax and deferred tax. Interest and penalties relating to income tax are also included in the 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.

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

Deferred tax liabilities are recognized for all taxable temporary differences except:

- Where the deferred tax liability arises on the initial recognition of goodwill; or
- 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, joint ventures 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, joint ventures 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.

Significant estimate or judgement

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. Therefore, judgement is required to determine provisions for income taxes.

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 current and deferred tax assets or liabilities, may arise in future periods. For more information see Note 35.

Judgement is also required when determining whether a particular tax is an income tax or another type of tax (for example a production tax). Accounting for deferred tax is applied to income taxes as described above, but is not applied to other types of taxes; rather such taxes are recognized in the income statement on an appropriate basis.

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. Shares repurchased under the share buy-back programme which are immediately cancelled are not shown as treasury shares or own shares, but are shown as a deduction from the profit and loss reserve in the group statement of changes in equity.

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.

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

Generally, revenues from the production of oil and natural gas properties in which the group has an interest with joint operation 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.

Impact of new International Financial Reporting Standards

Adopted for 2013

BP adopted several new and amended standards issued by the IASB with effect from 1 January 2013. Of these the following two standards have a significant effect on the group s consolidated financial statements:

IFRS 11 Joint Arrangements

In May 2011, the IASB issued IFRS 11 Joint Arrangements , one of a suite of standards relating to interests in other entities and related disclosures. 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 are accounted for using the equity method. Investments in joint operations are accounted for by recognizing the group s assets, liabilities, revenue and expenses relating to the joint operation.

The main impact of IFRS 11 is that certain of the group s former jointly controlled entities, which were equity accounted, now fall under the definition of a joint operation under IFRS 11. Whilst the effect of the new requirements on the group s reported income and net assets is not material, the change does impact certain of the component lines of the group s financial statements, as shown in the table below. We have derecognized approximately $7 billion of investments and we now recognize the group s assets, liabilities, revenue and expenses relating to these arrangements. BP s share of oil and natural gas reserves associated with former jointly controlled entities that were previously equity-accounted, and are now classified as joint operations, have been reclassified from equity-accounted entities to subsidiaries in the Supplementary information on oil and natural gas.

Amendments to IAS 19 Employee Benefits

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 is that the expense for defined benefit pension and other post-retirement benefit plans now includes a net interest income or expense, which is calculated by taking 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 (previously calculated based on the expected long-term return on pension assets) is now based on a lower corporate bond rate, the same rate that is used to discount the pension liability. The impact was to decrease profit before tax by $1,001 million for the year ended 31 December 2013 (2012 $763 million, 2011 $659 million) with other comprehensive income being increased by the same amount. There was no impact on the balance sheet at 31 December or on cash flows.

Adjustments made to certain selected financial statement line items

The following table sets out the adjustments made to certain selected financial statement line items of the previously reported comparative amounts as a result of the adoption of the amended IAS 19 Employee Benefits and the new standard IFRS 11 Joint Arrangements .

$ million (except per share amounts)

Selected lines only	As reported	IFRS 11	IAS 19	2012 As restated	As reported	IFRS 11	IAS 19	2011 As restated[a]
Income statement								
Earnings from joint ventures after interest and tax	744	(484)		260	1,304	(537)		767
Net finance income (expense) relating to pensions and other post-retirement benefits	201	(4)	(763)	(566)	263	(4)	(659)	(400)
Profit for the year	11,816	22	(587)	11,251	26,097	2	(490)	25,609
Earnings per share cents								
Profit for the year attributable to BP shareholders								
Basic	60.86	0.12	(3.09)	57.89	135.93	0.01	(2.59)	133.35
Diluted	60.45	0.11	(3.06)	57.50	134.29	0.01	(2.56)	131.74
Balance sheet								
Property, plant and equipment	120,448	4,883		125,331	119,214	4,217		123,431
Intangible assets	24,041	591		24,632	21,102	551		21,653
Investments in joint ventures	15,724	(7,110)		8,614	15,518	(7,215)		8,303

Net assets	119,620	132		119,752	112,482	103		112,585
Cash flow statement								
Profit (loss) before taxation	18,809	85	(763)	18,131	38,834	53	(659)	38,228
Net cash provided by operating activities	20,397	82		20,479	22,154	64		22,218
Net cash used in investing activities	(12,962)	(113)		(13,075)	(26,633)	(120)		(26,753)
Increase (decrease) in cash and cash equivalents	5,481	(23)		5,458	(4,489)	(62)		(4,551)

[a] Balance sheet amounts presented are as at 1 January 2012.

Table of Contents

1. Significant accounting policies, judgements, estimates and assumptions continued

Detailed restated financial information for 2012 and 2011 is shown in *BP Financial and Operating Information 2008-2012* available on *bp.com/investors.*

Other standards

A number of other new or amended standards have been adopted by the group with effect from 1 January 2013 but do not have a significant impact on the financial statements. These include:

IFRS 10 Consolidated Financial Statements 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. There was no effect on the group s reported income or net assets as a result of the adoption of IFRS 10.

IFRS 12 Disclosures of Interests in Other Entities combines all the disclosure requirements for an entity s interests in subsidiaries, joint arrangements, associates and structured entities into one comprehensive disclosure standard. There was no effect on the group s reported income or net assets as a result of the adoption of IFRS 12. The disclosures required by the standard are included in this report.

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. There was no significant impact on the group s reported income or net assets as a result of the adoption of IFRS 13. The disclosures required by the new standard are included in this report.

In December 2011, the IASB issued an amendment to IFRS 7 Disclosures Offsetting Financial Assets and Financial Liabilities . This amendment introduces new disclosure requirements about the effects of offsetting financial assets and financial liabilities and related arrangements on an entity s balance sheet. The new disclosures are included in this report.

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. The adoption of the amended standard has a presentational impact on the group s statement of comprehensive income, with no effect on the reported income, total comprehensive income, or net assets of the group. The presentation required by the amended standard is included in this report.

In May 2013, the IASB issued an amendment to IAS 36 Impairment of Assets in relation to the disclosure of recoverable amounts for non-financial assets. The amendment addressed certain unintended consequences arising from consequential amendments made to IAS 36 when IFRS 13 was issued. Although the mandatory effective date for application of the amendment is for annual periods beginning on or after 1 January 2014, the group has early-adopted it in these financial statements.

In addition, a number of other standards and interpretations were adopted in the year which had no significant impact on the group s reported income and net assets.

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.

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 and in November 2013 the IASB published revised guidance for hedge accounting. The remaining phase of IFRS 9, dealing with impairment, and further changes to the classification and measurement requirements, are still to be completed. In November 2013, the IASB also removed the effective date from IFRS 9 and will decide on an effective date when the entire IFRS 9 project is closer to completion. BP has not yet decided the date of adoption for the group and has not yet completed its evaluation of the effect of adoption. The EU has not yet adopted IFRS 9.

In December 2011, the IASB issued an amendment to IAS 32 Offsetting Financial Assets and Financial Liabilities . This amendment clarifies the presentation requirements in relation to offsetting financial assets and financial liabilities on an entity s balance sheet. The amendment to IAS 32 is effective for annual periods beginning on or after 1 January 2014. BP s evaluation of the effect of adoption of the amendment to IAS 32 is substantially complete, and is not expected to result in any significant changes to the offsetting of financial assets and liabilities on the group s balance sheet.

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.

Table of Contents

2. Significant event Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill in April 2010, BP continues to incur costs and has also recognized liabilities for certain future costs. Liabilities of uncertain timing or amount, for which no provision has been made, have been disclosed as contingent liabilities.

The cumulative pre-tax income statement charge since the incident amounts to $42.7 billion. For more information on the types of expenditure included in the cumulative income statement charge, see Impact upon the group income statement below. 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, including developments in relation to the interpretation of business economic loss claims under the Plaintiffs Steering Committee (PSC) settlement, see Provisions and contingent liabilities below.

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 under Provisions and contingent liabilities below, 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 under Risk factors on page 51 and Legal proceedings on page 257.

The impacts of the Gulf of Mexico oil spill on the income statement, balance sheet and cash flow statement of the group are included within the relevant line items in those statements and are shown in the table below.

$ million

		2013		2012		2011
	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	**430**	**(1,542)**	4,995	(1,191)	(3,800)	(3,995)
Profit (loss) before interest and taxation	**(430)**	**1,542**	(4,995)	1,191	3,800	3,995
Finance costs	**39**		19	12	58	52
Profit (loss) before taxation	**(469)**	**1,542**	(5,014)	1,179	3,742	3,943
Less: Taxation	**73**		94		(1,387)	
Profit (loss) for the period	**(396)**	**1,542**	(4,920)	1,179	2,355	3,943
Balance sheet						
Current assets						
Trade and other receivables	**2,457**	**2,457**	4,239	4,178		
Current liabilities						

Trade and other payables	**(1,030)**	**(1)**	(522)	(22)		
Provisions	**(2,951)**		(5,449)			
Net current assets (liabilities)	**(1,524)**	**2,456**	(1,732)	4,156		
Non-current assets						
Other receivables	**2,442**	**2,442**	2,264	2,264		
Non-current liabilities						
Other payables	**(2,986)**		(175)			
Provisions	**(6,395)**		(9,751)			
Deferred tax	**2,748**		4,002			
Net non-current assets (liabilities)	**(4,191)**	**2,442**	(3,660)	2,264		
Net assets (liabilities)	**(5,715)**	**4,898**	(5,392)	6,420		
Cash flow statement						
Profit (loss) before taxation	**(469)**	**1,542**	(5,014)	1,179	3,742	3,943
Finance costs	**39**		19	12	58	52
Net charge for provisions, less payments	**1,129**		4,834		2,699	
(Increase) decrease in other current and non-current assets	**(1,481)**	**(1,542)**	(998)	(1,191)	(4,292)	(4,038)
Increase (decrease) in other current and non-current liabilities	**(618)**		(5,090)	(4,860)	(11,113)	(10,097)
Pre-tax cash flows	**(1,400)**		(6,249)	(4,860)	(8,906)	(10,140)

The impact on net cash provided by operating activities, on a post-tax basis, amounted to an outflow of $73 million (2012 outflow of $2,382 million and 2011 outflow of $6,813 million).

Trust fund

BP established the Deepwater Horizon Oil Spill Trust (the Trust) in 2010, to be funded in the amount of $20 billion, to satisfy legitimate individual and business claims, 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 fund the qualified settlement funds (QSFs) established under the terms of the settlement agreements (comprising the Economic and Property Damages (EPD) Settlement Agreement and the Medical Benefits Class Action Settlement) with the PSC administered through the Deepwater Horizon Court Supervised Settlement Program (DHCSSP), and the separate BP claims programme see Provisions and contingent liabilities below for further information. Fines and penalties are not covered by the trust fund.

The funding of the Trust was completed in the fourth quarter of 2012. The obligation to fund the $20-billion trust fund, adjusted to take account of the time value of money, was recognized in full in 2010 and charged to the income statement.

BP s rights and obligations in relation to the $20-billion trust fund are accounted for in accordance with IFRIC 5 Rights to Interests Arising from Decommissioning, Restoration and Environmental Rehabilitation Funds . 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 from the trust fund, and BP will be released from its corresponding obligation. The reimbursement asset is recorded within other receivables on the balance sheet apportioned between current and non-current elements. The table below shows movements in the

Table of Contents

2. Significant event Gulf of Mexico oil spill continued

reimbursement asset during the period to 31 December 2013. The net increase in the provision of $1,542 million for the full year relates principally to business economic loss claims processed by the DHCSSP subsequent to finalization of the *BP Annual Report and Form 20-F 2012* that have been paid as well as increases in the provision for claims administration costs. The amount of the reimbursement asset at 31 December 2013 is equal to the amount of provisions and payables recognized at that date that will be covered by the trust fund see below.

$ million

	2013	2012	Cumulative since the incident
At 1 January	**6,442**	9,875	
Increase in provision for items covered by the trust fund	**1,921**	1,985	20,511
Derecognition of provision for items that cannot be reliably estimated	**(379)**	(794)	(1,173)
Amounts paid directly by the trust fund	**(3,085)**	(4,624)	(14,439)
At 31 December	**4,899**	6,442	4,899
Of which current	**2,457**	4,178	2,457
non-current	**2,442**	2,264	2,442

Any increases in estimated future expenditure that will be covered by the trust fund (up to an aggregate of $20 billion) have no net income statement effect as a reimbursement asset is also recognized, as described above. As at 31 December 2013, the cumulative charges, and the associated reimbursement asset recognized, amounted to $19,338 million. Thus, a further $662 million could be charged in subsequent periods for items covered by the trust fund with no net impact on the income statement. Additional liabilities in excess of this amount regarding claims under the Oil Pollution Act of 1990 (OPA 90), claims that are currently administered by the DHCSSP, or otherwise, including the various claims described in Legal proceedings on page 257, would be expensed to the income statement. Information on those items that currently cannot be estimated reliably is provided under Provisions and contingent liabilities below.

Under the terms of the EPD Settlement Agreement with the PSC, several QSFs were established in 2012. These QSFs each relate to specific elements of the agreement, have been and will continue to 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 2013, the aggregate cash balances in the Trust and the QSFs amounted to $6.7 billion, including $1.2 billion remaining in the seafood compensation fund which has yet to be distributed and $0.9 billion held for natural resource damage early restoration. Should the cash balances in the trust fund not be sufficient, payments in respect of legitimate claims and other costs will be made directly by BP.

The EPD Settlement Agreement with the PSC provides for a court-supervised settlement programme which commenced operation on 4 June 2012. See Provisions below for further information on the current status of the EPD Settlement Agreement. In addition, a separate BP claims programme began processing claims from claimants not in the Economic and Property Damages class as determined by the EPD Settlement Agreement or who have requested to opt out of that settlement. Payments made to claimants through the BP claims programme are paid directly from the Trust. A separate claims administrator has been appointed to pay medical claims and to implement other aspects of the

Medical Benefits Class Action Settlement. For further information on the PSC settlements, see Legal proceedings on page 257.

Other payables

BP reached an agreement with the US government in 2012, which was approved by the court in 2013, to resolve all federal criminal claims arising from the incident. Under the agreement, BP will pay $4 billion over a period of five years. At 31 December 2013, the remaining payable was $3,525 million, of which $565 million falls due in 2014.

BP also reached a settlement with the US Securities and Exchange Commission (SEC) in 2012, resolving the SEC s Gulf of Mexico oil spill-related civil claims. As part of the settlement, BP agreed to a civil penalty of $525 million. At 31 December 2013 the remaining payable, due in 2014, was $175 million plus accrued interest.

The amounts described above were reclassified from provisions to other payables upon court approval of the agreement with the US government and settlement with the SEC.

Provisions and contingent liabilities

Provisions

BP has recorded provisions relating to the Gulf of Mexico oil spill in relation to environmental expenditure, spill response costs, litigation and claims, and Clean Water Act penalties that can be measured reliably at this time.

Movements in each class of provision during the year and cumulatively since the incident are presented in the tables below.

					$ million 2013
	Environmental	Spill response	Litigation and claims	Clean Water Act	Total
At 1 January	1,862	345	9,483	3,510	15,200
Increase (decrease) in provision items not covered by the trust fund	(24)	(66)	408		318
items covered by the trust fund	24		1,897		1,921
Derecognition of provision for items that cannot be reliably estimated[a]			(379)		(379)
Reclassification of amounts between categories of provision	47	(47)			
Unwinding of discount	1				1
Change in discount rate	(5)				(5)
Reclassified to other payables items covered by the trust fund			(84)		(84)
items not covered by the trust fund			(3,849)		(3,849)
Utilization paid by BP	(60)	(143)	(523)		(726)
paid by the trust fund	(255)		(2,796)		(3,051)
At 31 December	1,590	89	4,157	3,510	9,346

Of which	current	389	84	2,478		2,951
	non-current	1,201	5	1,679	3,510	6,395
Of which	payable from the trust fund	1,253		3,595		4,848

[a] Relates to items covered by the trust fund.

Table of Contents

2. Significant event Gulf of Mexico oil spill continued

					$ million
	Cumulative since the incident				
	Environmental	Spill response	Litigation and claims	Clean Water Act	Total
Increase in provision items not covered by the trust fund	544	11,456	8,529	3,510	24,039
items covered by the trust fund	2,353	56	18,102		20,511
Derecognition of provision for items that cannot be reliably estimated[a]			(1,173)		(1,173)
Reclassification of amounts between categories of provision	47	(47)			
Unwinding of discount	12		6		18
Change in discount rate	17				17
Reclassified to other payables items covered by the trust fund			(84)		(84)
items not covered by the trust fund			(4,199)		(4,199)
Utilization paid by BP	(237)	(11,367)	(3,773)		(15,377)
paid by the trust fund	(1,146)	(9)	(13,251)		(14,406)
At 31 December 2013	1,590	89	4,157	3,510	9,346

[a] Relates to items covered by the trust fund.

Environmental

The environmental provision includes $320 million for BP s commitment to fund the Gulf of Mexico Research Initiative, which is a 10-year research programme to study the impact of the incident on the marine and shoreline environment of the Gulf of Mexico. In addition, BP faces claims under the Oil Pollution Act of 1990 (OPA 90) for natural resource damages. These damages include, among other things, the reasonable costs of assessing the injury to natural resources. 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. At 31 December 2013 the amount provided for natural resource damage assessment costs and early restoration projects was $1,224 million. 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.

Spill response

The spill response provision relates primarily to ongoing shoreline operational activity.

Litigation and claims

The litigation and claims provision includes amounts that can be estimated reliably for the future cost of settling claims by individuals and businesses for 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 claims by state and local government entities for removal costs, damage to real or personal property, loss of government revenue and increased public services costs (State and Local Claims), under OPA 90 and other legislation, except as described under Contingent liabilities below. Claims administration costs and legal costs have also been provided for. The timing of payment of litigation and claims provisions classified as non-current is dependent on on-going legal activity and is therefore uncertain.

BP has provided for its best estimate of the cost associated with the PSC settlement agreements with the exception of the cost of business economic loss claims. As part of its monitoring of payments made by the DHCSSP, BP identified multiple business economic loss claim determinations that appeared to result from an interpretation of the EPD Settlement Agreement by the claims administrator that BP believes was incorrect.

Between March 2013 and March 2014, there were various rulings from both the federal District Court in New Orleans (the District Court) and a panel of the US Court of Appeals for the Fifth Circuit (the business economic loss panel) on matters relating to the interpretation of the EPD Settlement Agreement, in particular on the issue of matching revenue and expenses as well as causation requirements of the EPD Settlement Agreement.

As reported in *BP Annual Report and Form 20-F 2012*, the estimated cost of the PSC settlement for Individual and Business Claims was $7.7 billion at 31 December 2012. This estimate increased during the year to $9.6 billion to reflect all claims processed by the DHCSSP for which eligibility notices had been issued and increases in claims administration costs. As a result of the District Court s preliminary injunction issued on 18 October 2013 that, amongst other things, required the claims administrator to temporarily suspend payments of business economic loss claims other than those claims supported by sufficiently matched accrual-basis accounting or any other business economic loss claim for which the claims administrator determines that the matching of revenue and expenses is not an issue, the provision for $0.4 billion of claims for which eligibility notices had been issued but had not yet been paid was derecognized as BP considered and continues to consider that no reliable estimate can be made for these claims. At 31 December 2013, the total costs of the PSC settlement that BP considers can be reliably estimated is therefore $9.2 billion.

On 5 December 2013, the District Court amended its earlier preliminary injunction and temporarily suspended the issuance of final determination notices and payments of business economic loss claims, until the business economic loss issues have been resolved. On 24 December 2013, the District Court ruled on the issues in relation to the matching of revenue and expenses and causation that were remanded to it by the business economic loss panel. Regarding matching, the District Court reversed its earlier decision and ruled that the claims administrator, in administering business economic loss claims, must match revenue with the variable expenses incurred by claimants in conducting their business, even where the revenues and expenses were recorded at different times. The District Court assigned to the claims administrator the development of more detailed matching requirements. On 12 February 2014, the claims administrator issued a draft policy addressing the matching of revenue and expenses for business economic loss claims. The parties have made written submissions on the draft policy and the claims administrator will issue a final policy to which BP and the PSC have the right to object and seek review by the District Court. Regarding causation, the District Court ruled that the EPD Settlement Agreement contained no causation requirement beyond the revenue and related tests set out in an exhibit to that agreement. BP appealed the District Court s ruling on causation to the business economic loss panel and moved for a permanent injunction that would prevent the claims administrator from making awards to claimants whose alleged injuries are not traceable to the spill. On 3 March 2014, the business economic loss panel affirmed the District Court s ruling on causation and denied BP s motion for a permanent injunction. BP is considering its appeal options, including a potential petition that all the active judges of the Fifth Circuit review the 3 March decision. Under the terms of the business economic loss panel s ruling, the injunction temporarily suspending issuance of final determination notices and payments of business economic loss claims will be lifted when the matter is transferred back to the District Court; the timing of this would be affected by the status of any such petition by BP.

2. Significant event Gulf of Mexico oil spill continued

In addition to the proceedings in relation to the interpretation of the EPD Settlement Agreement, following the District Court s final order and judgment approving the EPD Settlement in January 2013, groups of purported members of the Economic and Property Damages Settlement Class (the Appellants) appealed from the District Court s approval of that settlement to a different panel of the Fifth Circuit. On 10 January 2014, that other panel

of the Fifth Circuit affirmed the District Court s approval of the EPD Settlement but left to the business economic loss panel of the Fifth Circuit the question of how to interpret the EPD Settlement Agreement, including the meaning of the causation requirements of that agreement (see above). BP and several Appellants have filed petitions requesting that all the active judges of the Fifth Circuit review the decision to uphold approval of the EPD Settlement.

See Legal proceedings on page 257 for further details on the settlements with the PSC and related matters.

Until the uncertainties described below are resolved, management is unable to estimate reliably the value and volume of future business economic loss claims and whether and to what extent received or processed but unpaid business economic loss claims will be paid. Firstly, the inherent uncertainty as to the interpretation of the EPD Settlement Agreement in respect of matching and causation issues will continue until the more detailed matching requirements are finalized by the claims administrator and are implemented by the DHCSSP; the issue of causation and the requirements for class membership under the EPD Settlement Agreement are resolved on appeal; and the impact of any new policies and procedures in response to these issues on the value and volume of business economic loss claims becomes clear. Furthermore, the Fifth Circuit has yet to decide whether to grant the petitions seeking review of its decision affirming approval of the EPD Settlement and, if granted, whether to alter its decision in that appeal. Secondly, uncertainty arises from the lack of sufficient claims data under the DHCSSP from which to extrapolate any reliable trends the number of business economic loss claims received and the average amounts paid in respect of such claims prior to the District Court s injunction were higher than previously assumed by BP. This inability to extrapolate any reliable trends may or may not continue once the uncertainties concerning the interpretation of the EPD Settlement Agreement described above have been resolved. Thirdly, there is uncertainty as to the ultimate deadline for filing business economic loss claims, which is dependent on the date on which all relevant appeals are concluded. Management believes, therefore, that no reliable estimate can currently be made of any business economic loss claims not yet received, processed and paid by the DHCSSP. A provision for business economic loss claims will be established when a reliable estimate can be made of the liability.

The total cost of the PSC settlement is likely to be significantly higher than the amount recognized to date of $9.2 billion because the current estimate does not reflect business economic loss claims not yet received, processed and paid. The DHCSSP has issued eligibility notices, disputed by BP, in respect of business economic loss claims of $1,019 million which have not yet been paid. Furthermore, a significant number of business economic loss claims have been received but have not yet been processed, and further claims are likely to be received.

The provision recognized for litigation and claims includes an estimate for State and Local 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. See Legal proceedings on page 257 and Contingent liabilities below for further details.

Clean Water Act penalties

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 to 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.

BP intends to argue for a penalty lower than $1,100 per barrel. 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. 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), 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 is subject to significant uncertainty since it will depend on what is determined by the court in the federal multi-district litigation proceedings in New Orleans (MDL 2179) as to negligence, gross negligence or wilful misconduct, the volume of oil spilled and the application of statutory penalty factors. The trial court could issue its decision on the first two phases of the trial (which considered the issues of negligence or gross negligence in phase one, and source control efforts and the volume of oil spilled in phase two) at any time and has not yet scheduled a hearing on the subsequent phase regarding the application of statutory penalty factors. The court has wide discretion in its determination as to whether a defendant s conduct involved negligence or gross negligence as well as in its determinations on the volume of oil spilled and the application of statutory penalty factors.

Table of Contents

2. Significant event Gulf of Mexico oil spill continued

See Legal proceedings on page 257 for further details on all litigation and claims activity.

Provision movements

The total amount recognized as an increase in provisions during the year was $2,239 million, including $1,921 million for items covered by the trust fund and $318 million for other items (2012 $6,868 million, including $1,985 million for items covered by the trust fund and $4,883 million for other items). In addition, $379 million (2012 $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 $3,777 million, including payments from the trust fund of $3,051 million and payments made directly by BP of $726 million (2012 $5,864 million, including payments from the trust fund of $4,624 million and payments made directly by BP of $1,240 million), and after reclassifications and adjustments for discounting, the remaining provision as at 31 December 2013 was $9,346 million (2012 $15,200 million).

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.

Contingent liabilities

BP has provided for its best estimate of amounts expected to be paid from the trust fund that can be measured reliably. This includes certain amounts expected to be paid pursuant to the Oil Pollution Act of 1990 (OPA 90). It is not possible, at this time, to measure reliably other obligations arising from the incident that are under the terms of the trust fund, namely any obligation in relation to natural resource damages claims or associated legal costs (except for the estimated costs of the assessment phase and costs relating to early restoration agreements under the $1-billion framework agreement referred to above), claims asserted in civil litigation including any further litigation through excluded parties from the PSC settlement including as set out in Legal proceedings, the cost of business economic loss claims under the PSC settlement not yet received, processed and paid by the DHCSSP, any further obligation that may arise from state and local government submissions 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 2013.

Natural resource damages resulting from the oil spill are currently being assessed. 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 address 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 such amounts have been provided as at 31 December 2013.

As described under Provisions above, BP has identified multiple business economic loss claim determinations under the PSC settlement that appeared to result from an interpretation of the EPD Settlement Agreement by the claims administrator that BP believes was incorrect. Uncertainty as to the interpretation of the EPD Settlement Agreement will continue until the effects of the implementation of new policies and procedures are known, the issue of causation and the requirements for class membership under the EPD Settlement Agreement are resolved on appeal and the courts have ruled on the appeals in relation to the final order and judgment approving the EPD Settlement. Therefore the potential cost of business economic loss claims not yet received, processed and paid is not provided for and is disclosed as a contingent liability. A significant number of business economic loss claims have been received but have not yet been processed and paid, and further claims are likely to be received.

As described above in Provisions, a provision has been made for State and Local claims that can be measured reliably. In January 2013, the States of Alabama, Mississippi and Florida submitted or asserted 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 States of Louisiana and Texas have also asserted similar claims. The amounts claimed, certain of which include punitive damages or other multipliers, are very substantial. However BP considers these claims unsubstantiated and the methodologies used to calculate these claims to be seriously flawed, not supported by OPA 90, not supported by documentation, and to substantially overstate the claims. Similar claims have also been submitted by various local government entities and a foreign government under OPA 90, and more claims are expected to be submitted. The amounts alleged in the submissions for these State and Local Claims total approximately $35 billion. BP will defend vigorously against these claims if adjudicated at trial.

Proceedings relating to securities class actions (MDL 2185) pending in federal court in Texas, including a purported class action on behalf of purchasers of American Depository Shares under US federal securities law, are continuing. A jury trial is scheduled to begin in October 2014. No reliable estimate can be made of the amounts that may be payable in relation to these proceedings, if any, so no provision has been recognized at 31 December 2013.

In addition to the State and Local claims and securities class actions described above, BP is named as a defendant in approximately 2,950 other civil lawsuits brought by individuals, corporations 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 lawsuits. Therefore no amounts have been provided for these items as at 31 December 2013. See Legal proceedings on page 257 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 above, 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 unsubstantiated nature of certain 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.

2. Significant event Gulf of Mexico oil spill continued

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 2013.

The magnitude and timing of all possible obligations in relation to the Gulf of Mexico oil spill continue to be subject to a very high degree of uncertainty as described further in Risk factors on page 51. 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.

Impact upon the group income statement

The amount of the provision recognized during the year can be reconciled to the charge to the income statement as follows:

				$ million
	2013	2012	2011	Cumulative since the incident
Net increase in provision	**2,239**	6,868	5,183	44,551
Derecognition of provision for items that cannot be reliably estimated	**(379)**	(794)		(1,173)
Change in discount rate relating to provisions	**(5)**		17	17
Costs charged directly to the income statement	**136**	257	512	4,244
Trust fund liability discounted				19,580
Change in discounting relating to trust fund liability			43	283
Recognition of reimbursement asset, net	**(1,542)**	(1,191)	(4,038)	(19,338)
Settlements credited to the income statement	**(19)**	(145)	(5,517)	(5,681)
(Profit) loss before interest and taxation	**430**	4,995	(3,800)	42,483
Finance costs	**39**	19	58	193
(Profit) loss before taxation	**469**	5,014	(3,742)	42,676

The group income statement for 2013 includes a pre-tax charge of $469 million (2012 pre-tax charge of $5,014 million) in relation to the Gulf of Mexico oil spill. The costs charged in 2013 relate primarily to the ongoing costs of operating the Gulf Coast Restoration Organization (GCRO) and increases in legal costs. Finance costs of $39 million (2012 $19 million) reflect the unwinding of the discount on payables and provisions. The cumulative amount charged to the income statement to date comprises spill response costs arising in the aftermath of the incident, GCRO operating costs, amounts charged upon initial recognition of the trust obligation, litigation, claims, environmental and legal costs not paid through the Trust, estimated obligations for future costs that can be estimated reliably at this time and rights and obligations relating to the trust fund, net of settlements agreed with the co-owners of the Macondo well and other third parties.

The total amount recognized in the income statement is analysed in the table below.

$ million

	2013	2012	2011	Cumulative since the incident
Trust fund liability discounted				19,580
Change in discounting relating to trust fund liability			43	283
Recognition of reimbursement asset	**(1,542)**	(1,191)	(4,038)	(19,338)
Other				8
Total (credit) charge relating to the trust fund	**(1,542)**	(1,191)	(3,995)	533
Environmental amount provided	**47**	801	1,167	2,944
change in discount rate relating to provisions	**(5)**		17	17
costs charged directly to the income statement				70
Total (credit) charge relating to environmental	**42**	801	1,184	3,031
Spill response amount provided	**(113)**	109	586	11,465
costs charged directly to the income statement		9	85	2,839
Total (credit) charge relating to spill response	**(113)**	118	671	14,304
Litigation and claims amount provided, net of provision derecognized	**1,926**	5,164	3,430	25,459
costs charged directly to the income statement				184
Total charge relating to litigation and claims	**1,926**	5,164	3,430	25,643
Clean Water Act penalties amount provided				3,510
Other costs charged directly to the income statement	**136**	248	427	1,143
Settlements credited to the income statement	**(19)**	(145)	(5,517)	(5,681)
(Profit) loss before interest and taxation	**430**	4,995	(3,800)	42,483
Finance costs	**39**	19	58	193
(Profit) loss before taxation	**469**	5,014	(3,742)	42,676

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 under Provisions and contingent liabilities above.

Table of Contents

3. Business combinations

BP undertook a number of minor business combinations in 2013 and 2012 for a total consideration of $67 million and $116 million in cash respectively.

In 2011, BP undertook a number of business combinations with total consideration paid in cash amounting to $11.3 billion, offset by cash acquired of $0.4 billion. The fair value of contingent consideration payable amounted to $0.1 billion. 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. In addition, we completed the final part of the transaction with Devon Energy (Devon) for the acquisition of Devon s equity stake in a number of assets in Brazil for consideration of $3.6 billion and BP s Alternative Energy business acquired Companhia Nacional de Açúcar e Álcool (CNAA) in Brazil for consideration of $0.7 billion. There were a number of other individually insignificant business combinations.

4. Non-current assets held for sale

There were no assets or associated liabilities classified as held for sale as at 31 December 2013. The disposal of the assets and associated liabilities classified as held for sale at 31 December 2012 completed during 2013.

Impairment losses amounting to $186 million (2012 $2,594 million) were recognized relating to certain assets that were classified as held for sale at 31 December 2012, of which $137 million related to the Carson refinery and associated assets. 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 held for sale at 31 December 2012 until their disposal in 2013 amounted to approximately $201 million (2012 $435 million). In addition, profits of approximately $738 million (2012 $731 million) were not recognized as a result of the discontinuance of equity accounting for our interest in TNK-BP.

Non-current assets held for sale at 31 December 2012

At 31 December 2012 assets classified as held for sale included property, plant and equipment of $3,663 million, investments in associates of $12,322 million and inventories of $2,377 million.

Within the Upstream segment, 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 in the central North Sea were classified as held for sale. In 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 held for sale at 31 December 2012. BP s investment in TNK-BP was classified as an asset held for sale at 31 December 2012. All of the assets classified as held for sale at 31 December 2012 were sold during 2013. See Notes 5 and 6 for further information.

5. Disposals and impairment

The following amounts were recognized in the income statement in respect of disposals and impairments.

$ million

	2013	2012	2011
Gains on sale of businesses and fixed assets			
Upstream	**371**	6,504	3,477
Downstream	**214**	152	319
TNK-BP	**12,500**		
Other businesses and corporate	**30**	41	336
	13,115	6,697	4,132

			$ million
	2013	2012	2011
Losses on sale of businesses and fixed assets			
Upstream	**144**	109	49
Downstream	**78**	195	52
Other businesses and corporate	**8**	6	3
	230	310	104
Impairment losses			
Upstream	**1,255**	3,046	1,443
Downstream	**484**	2,892	599
Other businesses and corporate	**218**	320	58
	1,957	6,258	2,100
Impairment reversals			
Upstream	**(226)**	(289)	(146)
Downstream		(1)	
Other businesses and corporate		(3)	
	(226)	(293)	(146)
Impairment and losses on sale of businesses and fixed assets	**1,961**	6,275	2,058

Table of Contents

5. Disposals and impairment continued

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. This target was reached during 2012; as at 31 December 2012, BP had announced disposals of $38 billion, and in addition, the sale of our 50% investment in TNK-BP. During 2013 the group announced that it expects to divest a further $10 billion of assets before the end of 2015.

			$ million
	2013	2012	2011
Proceeds from disposals of fixed assets	**18,115**	9,992	3,504
Proceeds from disposals of businesses, net of cash disposed	**3,884**	1,606	(663)
	21,999	11,598	2,841
By segment			
Upstream	**1,288**	10,667	1,080
Downstream	**3,991**	637	830
TNK-BP	**16,646**		
Other businesses and corporate	**74**	294	931
	21,999	11,598	2,841

Proceeds from disposals for 2012 included a deposit of $632 million received in respect of the disposal in 2013 of interests in a number of central North Sea oil and gas fields. Disposal proceeds for 2011 included the repayment of a deposit of $3,530 million received in 2010 in advance of the expected sale of our interest in Pan American Energy LLC, which did not complete.

At 31 December 2013, deferred consideration relating to disposals amounted to $23 million receivable within one year (2012 $24 million and 2011 $117 million) and $1,374 million receivable after one year (2012 $1,433 million and 2011 $1,524 million). In addition, contingent consideration relating to the disposals of the Devenick field and the Texas City refinery amounted to $953 million at 31 December 2013 see Notes 20 and 26 for further information.

Upstream

In 2013, the major disposal transaction in the segment was the sale of our interests in the BP-operated Maclure, Harding and Devenick fields and non-operated interests in the Brae complex of fields and the Braemar field in the central North Sea to TAQA. In addition, we sold our interests in the Yacheng field in China to Kuwait Foreign Petroleum Exploration Company, as well as other interests in the North Sea and the US.

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.

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.

Downstream

In 2013, gains resulted from the disposal of our global LPG business and closing adjustments on the sales of the Texas City and Carson refineries with their associated marketing and logistics assets. Losses principally resulted from the disposal of a number of assets, principally in our global fuels portfolio.

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.

TNK-BP

In 2013, BP disposed of its 50% interest in TNK-BP. See Note 6 for further information.

Other businesses and corporate

In 2011, we disposed of our aluminium business in the US which resulted in a gain.

Table of Contents

5. Disposals and impairment continued

Summarized financial information relating to the sale of businesses is shown in the table below. The principal transactions categorized as business disposals in 2013 were the sales of the Texas City and Carson refineries with their associated marketing and logistics assets. Information relating to sales of fixed assets is excluded from the table.

			$ million
	2013	2012	2011
Non-current assets	**2,124**	610	2,085
Current assets	**2,371**	570	1,008
Non-current liabilities	**(94)**	(263)	(212)
Current liabilities	**(62)**	(232)	(611)
Total carrying amount of net assets disposed	**4,339**	685	2,270
Recycling of foreign exchange on disposal	**23**	(15)	8
Costs on disposal[a]	**13**	39	17
	4,375	709	2,295
Profit on sale of businesses[b]	**69**	675	2,232
Total consideration	**4,444**	1,384	4,527
Consideration received (receivable)[c]	**(414)**	76	116
Proceeds from the sale of businesses related to completed transactions	**4,030**	1,460	4,643
Deposits received (repaid) related to assets classified as held for sale[d]		146	(3,530)
Disposals completed in relation to which deposits had been received in prior year	**(146)**		(1,776)
Proceeds from the sale of businesses[e]	**3,884**	1,606	(663)

[a] 2013 includes pension and other post-retirement benefit plan curtailment gains of $109 million.
[b] 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 former associate TNK-BP.
[c] Consideration received from prior year business disposals or to be received from current year disposals. 2013 includes contingent consideration of $475 million relating to the disposal of the Texas City refinery.
[d] 2011 relates to the repayment of a deposit received in advance of $3,530 million following the termination of the sale agreement in respect of the expected sale of our interest in Pan American Energy LLC.
[e] Substantially all of the consideration received was in the form of cash and cash equivalents. Proceeds are stated net of cash and cash equivalents disposed of $42 million (2012 $4 million and 2011 $14 million).

Impairment

Upstream

During 2013, the Upstream segment recognized impairment losses of $1,255 million. The main elements were impairment losses of $251 million and $159 million relating to the Browse project in Australia and the Mad Dog Phase 2 project in the Gulf of Mexico respectively, resulting from the selection of alternative development scenarios for both projects; write-downs of a number of assets in the North Sea, caused by increases in expected decommissioning costs, amounting to $253 million in aggregate; a $134-million write-down of pipelines in the North

Sea due to cost increases; a $122-million write-down to fair value less costs to sell based on expected proceeds resulting from a decision to divest our interest in the Polvo field in Brazil; and other impairment losses amounting to $335 million in total that were not individually significant. These impairment losses were partly offset by reversals of impairment of certain of our interests in Alaska, the Gulf of Mexico, and the North Sea amounting to $226 million in total, triggered by reductions in expected decommissioning costs, partly as a result of an increase in the discount rate for provisions.

During 2012, the Upstream segment recognized impairment losses of $3,046 million. The main elements were a $1,082-million write-down of our interests in the Fayetteville and Woodford shale gas assets in the US, due to reserves revisions, lower values being attributed to recent market transactions and a fall in the gas price; 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.

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.

Downstream

During 2013, the Downstream segment recognized impairment losses of $484 million which mainly relates to impairments of certain refineries in the US and elsewhere in our global fuels portfolio.

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, of which $398 million related to assets classified as held for sale. Other impairment losses, related to retail churn in Europe and other minor asset disposals, amounted to $201 million in total.

Other businesses and corporate

Impairment losses totalling $218 million, $320 million and $58 million were recognized in 2013, 2012 and 2011 respectively related to various assets in the Alternative Energy business. The amount for 2013 is principally in respect of our US wind 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.

Table of Contents

6. Disposal of TNK-BP and investment in Rosneft

Disposal of TNK-BP

BP announced on 22 November 2012 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 would consist of three tranches:

- BP to sell its 50% shareholding in TNK-BP to Rosneft for cash consideration of $25.4 billion (which included a dividend of $0.7 billion received from TNK-BP in December 2012) and Rosneft shares representing a 3.04% stake in Rosneft.
- BP would 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 price on the bid date of 18 October 2012).
- BP would 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 net result of the overall transaction was that BP would receive $12.3 billion in cash (including $0.7 billion of TNK-BP dividends received by BP in December 2012) and acquire an 18.5% shareholding in Rosneft. Combined with BP s existing 1.25% shareholding, this would result in BP owning 19.75% of Rosneft.

On completion, the transactions between BP, Rosneft and the Rosneft subsidiary were instead settled on a net basis, so that BP received the 9.80% stake in Rosneft directly rather than receiving and immediately paying $8.3 billion in cash; however, the net result was the same.

BP accounts for its investment in Rosneft as an associate, and so equity accounts for its share of Rosneft s earnings, production and reserves. See Note 18 for more information on BP s investment in Rosneft.

The gain on disposal of BP s investment in TNK-BP, recognized in the TNK-BP segment in 2013, was $12.5 billion as shown in the table below.

	$ million
Agreed cash disposal proceeds	25,425
Amount settled net in Rosneft shares (9.80% stake)	(8,309)
TNK-BP dividend received by BP in December 2012	(709)
Interest on cash proceeds	239
Disposal proceeds received in cash	16,646
Shares in Rosneft received (9.80% and 3.04% stake)	10,755
Consideration received	27,401
Less: carrying value of investment in TNK-BP	(12,393)
	15,008
Deferral of gain	(2,959)
Gain on existing 1.25% investment in Rosneft	523
Other	(72)

Gain on disposal of investment in TNK-BP	12,500

Disposal proceeds of $4.9 billion were used to purchase the 5.66% stake in Rosneft from Rosneftegaz ($4.8 billion described above plus $0.1 billion of interest). The net cash inflow relating to the transaction included in net cash flow from investing activities in the cash flow statement was $11.8 billion.

Part of the gain arising on the disposal, amounting to $3.0 billion, was deferred due to BP selling its investment in TNK-BP to Rosneft, which in turn is now accounted for by BP as an associate. The deferred gain will be released to BP s income statement over time as the TNK-BP assets are depreciated or amortized.

Investment in Rosneft

BP s investment in Rosneft is included in the group balance sheet within investments in associates, as described in Note 1. The investment is measured at cost less the deferred gain described above, plus post-acquisition changes in BP s share of Rosneft s net assets. The amount recognized as BP s initial investment in Rosneft was determined as shown in the table below.

	$ million
Shares in Rosneft received	10,755
Shares purchased from Rosneftegaz	4,871
Value of agreements to purchase Rosneft shares accounted for as derivatives (see Note 26)	(726)
Deferred gain	(2,959)
Amount included in capital expenditure	11,941
Value of existing 1.25% investment in Rosneft	1,006
Investment in Rosneft on completion	12,947

The exercise to determine BP s share of the fair value of Rosneft s identifiable net assets and the consequent impact recognized via equity accounting in BP s income statement has been completed and the results are reflected in these financial statements.

Table of Contents

7. Segmental analysis

The group s organizational structure reflects the various activities in which BP is engaged. At 31 December 2013, BP had three reportable segments: Upstream, Downstream and Rosneft.

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).

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.

During 2013, BP completed transactions for the sale of BP s interest in TNK-BP to Rosneft, and for BP s further investment in Rosneft. BP s interest in Rosneft is accounted for using the equity method and is reported as a separate operating segment, reflecting the way in which the investment is managed.

Other businesses and corporate comprises the Alternative Energy business, the group s shipping and treasury functions, and corporate activities worldwide. The Alternative Energy business is an operating segment which is reported within Other businesses and corporate as it does not meet the materiality thresholds for separate segment reporting.

The Gulf Coast Restoration Organization (GCRO), which manages all aspects of our response to the 2010 Gulf of Mexico incident, 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.

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.

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.

Table of Contents

7. Segmental analysis continued

$ million

By segment	Upstream	Downstream	Rosneft	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
								2013
Segment revenues								
Sales and other operating revenues	70,374	351,195			1,805		(44,238)	379,136
Less: sales and other operating revenues between segments	(42,327)	(1,045)			(866)		44,238	
Third party sales and other operating revenues	28,047	350,150			939			379,136
Equity-accounted earnings	1,027	195	2,058		(91)			3,189
Interest income	76	93			113			282
Segment results								
Replacement cost profit (loss) before interest and taxation	16,657	2,919	2,153	12,500	(2,319)	(430)	579	32,059
Inventory holding gains (losses)[a]	4	(194)	(100)					(290)
Profit (loss) before interest and taxation	16,661	2,725	2,053	12,500	(2,319)	(430)	579	31,769
Finance costs								(1,068)
Net finance expense relating to pensions and other post-retirement benefits								(480)
Profit before taxation								30,221
Other income statement items								
Depreciation, depletion and amortization								

US	**3,538**	**747**		**181**			**4,466**
Non-US	**7,514**	**1,343**		**187**			**9,044**
Impairment losses	**1,255**	**484**		**218**			**1,957**
Impairment reversals	**(226)**						**(226)**
Fair value (gain) loss on embedded derivatives	**(459)**						**(459)**
Charges for provisions, net of write-back of unused provisions, including change in discount rate	**161**	**270**		**295**	**1,855**		**2,581**
Segment assets							
Equity-accounted investments	**7,780**	**3,302**	**13,681**	**1,072**			**25,835**
Additions to non-current assets	**19,499**	**4,449**	**11,941**	**1,027**			**36,916**
Additions to other investments							**41**
Element of acquisitions not related to non-current assets							**39**
Additions to decommissioning asset							**(384)**
Capital expenditure and acquisitions	**19,115**	**4,506**	**11,941**	**1,050**			**36,612**

[a] See explanation of inventory holding gains and losses on page 149.

Table of Contents

7. Segmental analysis continued

$ million

By segment	Upstream	Downstream	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
							2012
Segment revenues							
Sales and other operating revenues	72,225	346,391		1,985		(44,836)	375,765
Less: sales and other operating revenues between segments	(42,572)	(1,365)		(899)		44,836	
Third party sales and other operating revenues	29,653	345,026		1,086			375,765
Equity-accounted earnings	915	101	2,986	(67)			3,935
Interest income	107	108		104			319
Segment results							
Replacement cost profit (loss) before interest and taxation	22,491	2,864	3,373	(2,794)	(4,995)	(576)	20,363
Inventory holding gains (losses)[a]	(104)	(487)	(3)				(594)
Profit (loss) before interest and taxation	22,387	2,377	3,370	(2,794)	(4,995)	(576)	19,769
Finance costs							(1,072)
Net finance expense relating to pensions and other post-retirement benefits							(566)
Profit before taxation							18,131
Other income statement items							
Depreciation, depletion and amortization							
US	3,437	586		213			4,236
Non-US	6,918	1,343		190			8,451
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, including change in discount rate	897	141		505	6,074		7,617
Segment assets							
Equity-accounted investments	7,329	3,212		1,071			11,612
Additions to non-current assets	22,603	5,246		1,419			29,268

Additions to other investments				33
Element of acquisitions not related to non-current assets				(72)
Additions to decommissioning asset				(4,025)
Capital expenditure and acquisitions	18,520	5,249	1,435	25,204

[a] See explanation of inventory holding gains and losses on page 149.

Table of Contents

7. Segmental analysis continued

							$ million
							2011
By segment	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	75,754	344,033		2,957		(47,031)	375,713
Less: sales and other operating revenues between segments	(44,766)	(1,396)		(869)		47,031	
Third party sales and other operating revenues	30,988	342,637		2,088			375,713
Equity-accounted earnings	1,150	381	4,185	(33)			5,683
Interest income	(10)	108		146			244
Segment results							
Replacement cost profit (loss) before interest and taxation	26,358	5,470	4,134	(2,468)	3,800	(113)	37,181
Inventory holding gains (losses)[a]	81	2,487	51	15			2,634
Profit (loss) before interest and taxation	26,439	7,957	4,185	(2,453)	3,800	(113)	39,815
Finance costs							(1,187)
Net finance expense relating to pensions and other post-retirement benefits							(400)
Profit before taxation							38,228
Other income statement items							
Depreciation, depletion and amortization							
US	3,201	860		151			4,212
Non-US	5,540	1,431		174			7,145
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	373		942	5,200		6,728

Segment assets					
Equity-accounted investments	7,301	3,256	10,013	1,024	21,594
Additions to non-current assets	34,813	4,281		1,864	40,958
Additions to other investments					27
Element of acquisitions not related to non-current assets					(1,089)
Additions to decommissioning asset					(7,937)
Capital expenditure and acquisitions	25,821	4,285		1,853	31,959

[a] See explanation of inventory holding gains and losses on page 149.

Table of Contents

7. Segmental analysis continued

$ million

By geographical area	US	Non-US	2013 Total
Revenues			
Third party sales and other operating revenues[a]	**128,764**	**250,372**	**379,136**
Other income statement items			
Production and similar taxes	**1,112**	**5,935**	**7,047**
Results			
Replacement cost profit before interest and taxation	**3,114**	**28,945**	**32,059**
Non-current assets			
Other non-current assets[b c]	**70,228**	**124,439**	**194,667**
Other investments			**1,565**
Loans			**763**
Trade and other receivables			**5,985**
Derivative financial instruments			**3,509**
Deferred tax assets			**985**
Defined benefit pension plan surpluses			**1,376**
Total non-current assets			**208,850**
Capital expenditure and acquisitions	**9,176**	**27,436**	**36,612**

[a] Non-US region includes UK $82,381 million.
[b] Non-US region includes UK $18,967 million.
[c] Excluding financial instruments, deferred tax assets and defined benefit pension plan surpluses.

$ million

By geographical area	US	Non-US	2012 Total
Revenues			
Third party sales and other operating revenues[a]	130,940	244,825	375,765
Other income statement items			
Production and similar taxes	1,472	6,686	8,158
Results			
Replacement cost profit before interest and taxation	180	20,183	20,363
Non-current assets			
Other non-current assets[b c]	66,751	107,844	174,595
Other investments			2,704
Loans			642
Trade and other receivables			5,961
Derivative financial instruments			4,294
Deferred tax assets			874
Defined benefit pension plan surpluses			12
Total non-current assets			189,082

Capital expenditure and acquisitions	10,541	14,663	25,204

[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.

Table of Contents

7. Segmental analysis continued

By geographical area	US	Non-US	$ million 2011 Total
Revenues			
Third party sales and other operating revenues[a]	131,488	244,225	375,713
Other income statement items			
Production and similar taxes	1,854	6,426	8,280
Results			
Replacement cost profit before interest and taxation	10,202	26,979	37,181
Non-current assets			
Other non-current assets[b c]	66,523	113,323	179,846
Other investments			2,635
Loans			824
Trade and other receivables			5,738
Derivative financial instruments			5,038
Deferred tax assets			611
Defined benefit pension plan surpluses			17
Total non-current assets			194,709
Capital expenditure and acquisitions	8,931	23,028	31,959

[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.

8. Income statement analysis

	2013	2012	$ million 2011
Interest and other income			
Interest income	**282**	319	244
Other income[a]	**495**	1,358	444
	777	1,677	688
Currency exchange losses (gains) charged (credited) to the income statement[b]	**180**	106	(69)
Expenditure on research and development	**707**	674	636
Finance costs			
Interest payable	**1,082**	1,234	1,151
Capitalized at 2% (2012 2.25% and 2011 2.63%)[c]	**(238)**	(390)	(349)
Unwinding of discount on provisions[d]	**147**	140	244
Unwinding of discount on other payables[d]	**77**	88	141
	1,068	1,072	1,187

[a] 2012 includes $709 million of dividends received from TNK-BP. See Note 6 for further information.
[b] Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.
[c] Tax relief on capitalized interest is approximately $62 million (2012 $93 million and 2011 $107 million).
[d] Unwinding of discount on provisions relating to the Gulf of Mexico oil spill was $1 million (2012 $7 million and 2011 $6 million) and unwinding of discount on other payables relating to the Gulf of Mexico oil spill was $38 million (2012 $12 million and 2011 $52 million). See Note 2 for further information on the financial impacts of the Gulf of Mexico oil spill.

9. Operating leases

In the case of an operating lease entered into by BP as the operator of a joint operation, 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 operators, whether the joint operators have co-signed the lease or not. Where BP is not the operator of a joint operation, 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
	2013	2012	2011
Minimum lease payments	**5,961**	5,257	4,868
Contingent rentals	**(50)**	(79)	(97)
Sub-lease rentals	**(88)**	(228)	(153)
	5,823	4,950	4,618

Table of Contents

9. Operating leases continued

The future minimum lease payments at 31 December 2013, before deducting related rental income from operating sub-leases of $223 million (2012 $271 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	**2013**	2012
Payable within		
1 year	**5,188**	4,533
2 to 5 years	**10,408**	9,735
Thereafter	**3,590**	4,195
	19,186	18,463

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 voyage-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 2013, the future minimum lease payments relating to drilling rigs amounted to $8,776 million (2012 $8,527 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.

10. 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
	2013	2012	2011
Exploration and evaluation costs			
Exploration expenditure written off[a]	**2,710**	745	1,024
Other exploration costs	**731**	730	496
Exploration expense for the year	**3,441**	1,475	1,520
Impairment losses	**253**		7
Impairment reversals		(42)	
Intangible assets exploration and appraisal expenditure	**20,865**	23,434	20,433
Liabilities	**212**	287	306
Net assets	**20,653**	23,147	20,127
Capital expenditure	**4,464**	5,176	8,926
Net cash used in operating activities	**731**	730	496
Net cash used in investing activities	**4,275**	5,010	8,571

[a] 2013 included an $845-million write-off relating to the value ascribed to block BM-CAL-13 offshore Brazil as a result of the Pitanga exploration well not encountering commercial quantities of oil or gas and a $257-million write-off of costs relating to the Risha concession in Jordan as our exploration activities did not establish the technical basis for a development project in the concession. For further information see Upstream Exploration on page 28.

The carrying amount, by location, of exploration and appraisal expenditure capitalized as intangible assets at 31 December 2013 is shown in the table below.

Carrying amount	Location
$1-2 billion	Angola; US North America gas
$2-3 billion	Canada; Egypt; India
$3-4 billion	Brazil
$4-5 billion	US Gulf of Mexico

Table of Contents

11. Taxation

Tax on profit

			$ million
	2013	2012	2011
Current tax			
Charge for the year	**5,724**	6,664	7,500
Adjustment in respect of prior years	**61**	252	111
	5,785	6,916	7,611
Deferred tax			
Origination and reversal of temporary differences in the current year	**529**	67	5,523
Adjustment in respect of prior years	**149**	(103)	(515)
	678	(36)	5,008
Tax charge on profit	**6,463**	6,880	12,619

In 2013, the total tax charge recognized within other comprehensive income was $1,374 million (2012 $270 million credit and 2011 $1,490 million credit), and the total tax credit recognized directly in equity was $33 million (2012 $6 million credit and 2011 $7 million credit). See Note 32 for further information.

Reconciliation of the effective tax rate

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective tax rate of the group on profit before taxation. With effect from 1 April 2013 the UK statutory corporation tax rate reduced from 24% to 23% on profits arising from activities outside the North Sea.

			$ million
	2013	2012	2011
Profit before taxation	**30,221**	18,131	38,228
Tax charge on profit	**6,463**	6,880	12,619
Effective tax rate	**21%**	38%	33%
	% of profit before taxation		
UK statutory corporation tax rate	**23**	24	26
Increase (decrease) resulting from			
UK supplementary and overseas taxes at higher or lower rates[a]	**4**	12	14
Tax reported in equity-accounted entities	**(2)**	(5)	(3)
Adjustments in respect of prior years	**1**	1	(1)
Movement in deferred tax not recognized	**2**	2	
Tax incentives for investment	**(2)**	(2)	(1)
Gulf of Mexico oil spill non-deductible costs		8	
Permanent differences relating to disposals[b]	**(8)**		(2)
Foreign exchange	**2**	(1)	1

Other	**1**	(1)	(1)
Effective tax rate	**21**	38	33

[a] Jurisdictions which contribute significantly to this item are Angola, with an applicable statutory tax rate of 50%, the UK, currently with an applicable statutory tax rate of 62% for North Sea activities, and Trinidad and Tobago, with an applicable statutory tax rate of 55%.

[b] For 2013, this relates to the non-taxable gain on disposal of our investment in TNK-BP; for 2011, this mainly relates to the sale of our Upstream interests in Columbia.

Table of Contents

11. Taxation continued

Deferred tax

$ million

	Income statement			Balance sheet	
	2013	2012	2011	**2013**	2012
Deferred tax liability					
Depreciation	**(474)**	(75)	4,774	**31,551**	32,065
Pension plan surpluses	**(691)**			**284**	
Other taxable temporary differences	**(199)**	(2,239)	141	**3,653**	3,671
	(1,364)	(2,314)	4,915	**35,488**	35,736
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**787**	(33)	224	**(2,026)**	(3,421)
Decommissioning, environmental and other provisions	**1,385**	1,872	(1,443)	**(11,301)**	(12,705)
Derivative financial instruments	**30**	(7)	24	**(579)**	(281)
Tax credits	**(174)**	1,802	(401)	**(888)**	(714)
Loss carry forward	**(343)**	(911)	(223)	**(2,585)**	(2,214)
Other deductible temporary differences	**357**	(445)	1,912	**(1,655)**	(2,032)
	2,042	2,278	93	**(19,034)**	(21,367)
Net deferred tax charge (credit) and net deferred tax liability	**678**	(36)	5,008	**16,454**	14,369
Of which deferred tax liabilities				**17,439**	15,243
deferred tax assets				**985**	874

$ million

Analysis of movements during the year in the net deferred tax liability	**2013**	2012
At 1 January	**14,369**	14,609
Exchange adjustments	**43**	(27)
Charge (credit) for the year on profit	**678**	(36)
Charge (credit) for the year in other comprehensive income	**1,397**	(272)
Charge (credit) for the year in equity	**(33)**	4
Acquisitions		11
Reclassified as assets/liabilities held for sale		48
Deletions		32
At 31 December	**16,454**	14,369

A summary of temporary differences, unused tax credits and unused tax losses for which deferred tax has not been recognized is shown in the table below.

$ billion

At 31 December		**2013**	2012
Unused tax losses[a]		**1.8**	0.9
Unused tax credits		**18.0**	18.3
of which	arising in the UK[b]	**16.3**	16.0
	arising in the US[c]	**1.7**	2.3
Other deductible temporary differences[d]		**11.2**	7.0
Other taxable temporary differences associated with investments in subsidiaries and equity-accounted entities		**0.5**	0.5

[a] Substantially all the tax losses have no fixed expiry date.

[b] The UK tax credits arise predominantly in overseas branches of UK entities based in jurisdictions with high tax rates. No deferred tax asset has been recognized on these tax credits as they are unlikely to have value in the future; UK taxes on these overseas branches are largely mitigated by double tax relief on the overseas tax. These tax credits have no fixed expiry date.

[c] The US tax credits expire 10 years after generation and will all expire in the period 2015-2021.

[d] Other deductible temporary differences of $0.7 billion are expected to expire in the period 2014-2020, the remainder do not have an expiry date.

			$ billion
Benefit of previously unrecognized deferred tax on current year tax charge	**2013**	2012	2011
Current tax benefit relating to the utilization of previously unrecognized tax losses			0.1
Current tax benefit relating to the utilization of previously unrecognized tax credits	**0.2**	0.4	0.1
Deferred tax benefit relating to the recognition of previously unrecognized tax credits	**0.2**	0.1	

Table of Contents

12. Dividends

The quarterly dividend expected to be paid on 28 March 2014 in respect of the fourth quarter 2013 is 9.5 cents per ordinary share ($0.57 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 17 March 2014. 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		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Dividends announced and paid in cash									
Preference shares							**2**	2	2
Ordinary shares									
March	**6.0013**	5.0958	4.3372	**9.0**	8.0	7.0	**1,621**	1,211	808
June	**5.8342**	5.1498	4.2809	**9.0**	8.0	7.0	**1,399**	1,448	794
September	**5.7630**	5.0171	4.3160	**9.0**	8.0	7.0	**1,245**	1,417	1,224
December	**5.8008**	5.5890	4.4694	**9.5**	9.0	7.0	**1,174**	1,216	1,244
	23.3993	20.8517	17.4035	**36.5**	33.0	28.0	**5,441**	5,294	4,072
Dividend announced, payable in March 2014				**9.5**			**1,733**		

The details of the scrip dividends issued are shown in the table below.

	2013	2012	2011
Number of shares issued (thousand)	**202,124**	138,406	165,601
Value of shares issued ($ million)	**1,470**	982	1,219

The financial statements for the year ended 31 December 2013 do not reflect the dividend announced on 4 February 2014 and expected to be paid in March 2014; this will be treated as an appropriation of profit in the year ended 31 December 2014.

13. Earnings per ordinary share

			Cents per share
	2013	2012	2011
Basic earnings per share	**123.87**	57.89	133.35
Diluted earnings per share	**123.12**	57.50	131.74

Basic earnings per ordinary share amounts are calculated by dividing the profit for the year attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. The average number of shares outstanding excludes treasury shares and the shares held by the Employee Share Ownership Plan trusts (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 dilutive effect of shares that are potentially issuable in connection with employee share-based payment plans using the treasury stock method.

			$ million
	2013	2012	2011
Profit attributable to BP shareholders	**23,451**	11,017	25,212
Less: dividend requirements on preference shares	**2**	2	2
Profit for the year attributable to BP ordinary shareholders	**23,449**	11,015	25,210

			Shares thousand
	2013	2012	2011
Basic weighted average number of ordinary shares	**18,931,021**	19,027,929	18,904,812
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**115,152**	129,959	231,388
	19,046,173	19,157,888	19,136,200

The number of ordinary shares outstanding at 31 December 2013, 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 18,611,489,958. Between 31 December 2013 and 18 February 2014, the latest practicable date before the completion of these financial statements, there was a net decrease of 171,061,543 in the number of ordinary shares outstanding as a result of share issues in relation to employee share-based payment plans. During the same period, the group repurchased 195 million of its own ordinary shares as part of the share repurchase programme announced on 22 March 2013.

Employee share-based payment plans

The group operates share and share option plans for directors and certain employees to obtain ordinary shares and ADSs in the company. Information on these plans for directors is shown in the Directors remuneration report on page 81.

Table of Contents

13. Earnings per ordinary share continued

The following table shows the number of shares potentially issuable under employee share option plans, including the number of options outstanding, the number of options exercisable at the end of each year, and the corresponding weighted average exercise prices. The dilutive effect of the employee share option plans at 31 December included in the diluted earnings per share is also shown.

Share options		**2013**		2012
	Number of options[a b] thousand	**Weighted average exercise price $**	Number of options[a b] thousand	Weighted average exercise price $
Outstanding	**286,725**	**7.71**	324,096	7.62
Exercisable	**127,290**	**10.01**	159,419	9.33
Dilutive effect	**23,169**	**n/a**	16,435	n/a

[a] Numbers of options shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).
[b] At 31 December 2013, the quoted market price of one BP ordinary share was $8.10 (2012 $6.94).

In addition, the group operates a number of equity-settled employee share plans under which share units are granted to the group s 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. The number of shares that are expected to vest each year under employee share plans are shown in the table below. The dilutive effect of the employee share plans at 31 December included in the diluted earnings per share is also shown.

Shares	**2013**	2012
	Number of shares[a]	Number of shares[a]
Vesting	**thousand**	thousand
Within one year	**35,442**	29,138
1 to 2 years	**120,056**	67,593
2 to 3 years	**115,387**	120,621
3 to 4 years	**14,231**	25,066
4 to 5 years	**123**	233
	285,239	242,651
Dilutive effect	**95,014**	95,683

[a] Numbers of shares shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).
There has been a net decrease of 32,378,757 in the number of potential ordinary shares in relation to employee share-based payment plans between 31 December 2013 and 18 February 2014.

Table of Contents

14. 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 2013	3,279	2,812	171,772	45,200	3,346	13,436	9,059	248,904
Exchange adjustments	(4)	(26)		(235)	5	(55)	(36)	(351)
Additions	120	286	14,272	4,386	299	51	625	20,039
Acquisitions				8				8
Transfers			4,365					4,365
Deletions	(20)	(45)	(2,718)	(447)	(474)	(118)	(257)	(4,079)
At 31 December 2013	3,375	3,027	187,691	48,912	3,176	13,314	9,391	268,886
Depreciation								
At 1 January 2013	514	1,023	87,965	18,628	2,119	8,409	4,915	123,573
Exchange adjustments	(6)	(1)		(61)	7	(28)	(7)	(96)
Charge for the year	37	129	10,334	1,616	278	347	502	13,243
Impairment losses	10	20	611	525		160	35	1,361
Impairment reversals			(209)			(17)		(226)
Transfers			365					365
Deletions	(5)	(30)	(2,003)	(330)	(434)	(38)	(184)	(3,024)
At 31 December 2013	550	1,141	97,063	20,378	1,970	8,833	5,261	135,196
Net book amount at 31 December 2013	2,825	1,886	90,628	28,534	1,206	4,481	4,130	133,690
Cost								
At 1 January 2012	3,169	2,942	176,988	41,319	3,140	12,753	8,611	248,922
Exchange adjustments	86	14		320	28	8	272	728
Additions	120	387	16,303	4,481	314	902	533	23,040
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)	(531)	(3,459)	(779)	(136)	(70)	(355)	(5,426)
At 31 December 2012	3,279	2,812	171,772	45,200	3,346	13,436	9,059	248,904
Depreciation								
At 1 January 2012	511	1,411	91,994	16,915	1,940	8,149	4,571	125,491
Exchange adjustments	8	13		228	25	6	151	431
Charge for the year	33	123	9,659	1,442	289	320	504	12,370
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)	(2,458)	(414)	(135)	(10)	(315)	(3,902)
At 31 December 2012	514	1,023	87,965	18,628	2,119	8,409	4,915	123,573
Net book amount at 31 December 2012	2,765	1,789	83,807	26,572	1,227	5,027	4,144	125,331
Net book amount at 1 January 2012	2,658	1,531	84,994	24,404	1,200	4,604	4,040	123,431
Assets held under finance leases at net book amount included above								
At 31 December 2013		**7**	**187**	**265**		**4**		**463**
At 31 December 2012		9	157	254		9		429
Assets under construction included above								
At 31 December 2013								**27,900**
At 31 December 2012								29,203

Table of Contents

15. Goodwill and impairment review of goodwill

		$ million
	2013	2012
Cost		
At 1 January	**12,804**	14,041
Exchange adjustments	**46**	160
Acquisitions	**44**	25
Reclassified as assets held for sale		(1,327)
Deletions	**(43)**	(95)
At 31 December	**12,851**	12,804
Impairment losses		
At 1 January	**614**	1,612
Impairment losses for the year	**56**	
Reclassified as assets held for sale		(977)
Deletions		(21)
At 31 December	**670**	614
Net book amount at 31 December	**12,181**	12,190
Net book amount at 1 January	**12,190**	12,429

Impairment review of goodwill

		$ million
Goodwill at 31 December	**2013**	2012
Upstream	**7,812**	7,862
Downstream	**4,277**	4,168
Other businesses and corporate	**92**	160
	12,181	12,190

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 allocated to all oil and gas assets in aggregate 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 readily available information about the fair value of a cash-generating unit, the recoverable amount is deemed to be the value in use for the purposes of performing an impairment test of goodwill, unless this would lead to an impairment loss. If goodwill would be impaired using value in use as the recoverable amount, a fair value less costs to sell assessment would be performed as this may lead to a higher recoverable amount.

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 2013 (2012 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
	2013	2012
Goodwill	**7,812**	7,862
Excess of recoverable amount over carrying amount	**6,811**	25,871

The table above shows the carrying amount of the goodwill for the segment and the excess of the recoverable amount, based upon a value in use calculation, over the carrying amount (the headroom).

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, based on current estimates of reserves. 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, operating costs and expected hydrocarbon production profiles up to 2023 are derived from the business segment plan. Estimated production volumes 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 reserve volumes approved as part of BP s centrally controlled process for the estimation of proved and probable reserves and total resources.

Table of Contents

15. Goodwill and impairment review of goodwill continued

Intangible assets are deemed to have a recoverable amount equal to their carrying amount. Consistent with prior years, the 2013 review for impairment was carried out during the fourth quarter.

The Brent oil price and Henry Hub natural gas price assumptions used in the impairment review of goodwill are shown in the table below.

						2013
	2014	**2015**	**2016**	**2017**	**2018**	**2019 and thereafter**
Brent oil price ($/bbl)	**108**	**102**	**97**	**93**	**90**	**90**
Henry Hub natural gas price ($/mmBtu)	**3.86**	**4.02**	**4.10**	**4.17**	**4.27**	**6.50**

						2012
	2013	2014	2015	2016	2017	2018 and thereafter
Brent oil price ($/bbl)	105	100	96	93	91	90
Henry Hub natural gas price ($/mmBtu)	3.96	4.25	4.42	4.61	4.82	6.50

Key assumptions for oil and gas prices for the first five years were derived from forward price curves in the fourth quarter. Prices in 2019 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. Due to the non-linear relationship of different variables, the calculations were performed using a number of simplifying assumptions, including assuming a change to the variable being tested only, therefore a detailed calculation at any given price may produce a different result.

It is estimated that if the oil price assumption for all future years was approximately equal to the current assumption for 2019 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 is estimated that if the price assumption for natural gas was around 24% lower than the current assumption for 2019 and beyond the headroom would be reduced to zero.

Estimated production volumes are based on detailed data for each field and take into account development plans 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 597mmboe per year (2012 576mmboe per year). It is estimated that if this production volume were to be reduced by around 2% for the whole period, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment.

It is estimated that if the discount rate was approximately 14% for the entire portfolio this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment.

Downstream

$ million

				2013				2012
	Rhine FVC	**Lubricants**	**Other**	**Total**	Rhine FVC	Lubricants	Other	Total
Goodwill	**643**	**3,518**	**116**	**4,277**	627	3,441	100	4,168
Excess of recoverable amount over carrying amount	**2,759**	**n/a**	**n/a**	**n/a**	2,411	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 $12.35 per barrel and 250mmbbl per year (2012 $12.30 per barrel and 246mmbbl 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 (2012 4%).

No reasonably possible change in the discount rate would cause the Rhine FVC unit s carrying amount to exceed its recoverable amount. It is estimated that if the refinery margin assumption was $1.9 per barrel lower than the current assumption, the recoverable amount would equal the carrying amount. It is also estimated that if the refinery throughput volume assumption was 32mmbbl per year lower than the current assumption, the recoverable amount would equal the carrying amount.

Lubricants

In certain circumstances IAS 36 allows the use of the most recent detailed calculations of the recoverable amount performed in an earlier period as the basis for the current year s goodwill impairment test. The most recent detailed calculation of the Lubricants unit s recoverable amount was performed in 2009 and this was used as the basis for the tests in 2010-2012 as the criteria of IAS 36 were met in each of those years. IAS 36 does not specify for how many years such an approach is appropriate and management determined that a re-performance of the test was appropriate in 2013 given the passage of time since 2009. There was no significant change in the outcome of this test compared to that in 2009.

The key assumptions to which the calculation of the value in use for the Lubricants unit is most sensitive are operating margins, sales volumes, and discount rate. Operating margin and sales volumes assumptions used in the detailed impairment review of goodwill calculation are consistent with the assumptions used in the Lubricant unit s business plan and values assigned to these key assumptions reflect past experience. No reasonably possible change in any of these key assumptions would cause the unit s carrying amount to exceed its recoverable amount. Cash flows beyond the plan period are extrapolated using a 3% growth rate (2009 3%).

Table of Contents

16. Intangible assets

						$ million
			2013			2012
	Exploration and appraisal expenditure	**Other intangibles**	**Total**	Exploration and appraisal expenditure	Other intangibles	Total
Cost						
At 1 January	**24,511**	**3,739**	**28,250**	21,216	3,500	24,716
Exchange adjustments		**(5)**	**(5)**		50	50
Acquisitions				(68)	80	12
Additions	**4,464**	**336**	**4,800**	5,244	343	5,587
Transfers	**(4,365)**		**(4,365)**	(1,306)		(1,306)
Reclassified as assets held for sale				(67)	(26)	(93)
Deletions	**(2,868)**	**(134)**	**(3,002)**	(508)	(208)	(716)
At 31 December	**21,742**	**3,936**	**25,678**	24,511	3,739	28,250
Amortization						
At 1 January	**1,077**	**2,541**	**3,618**	783	2,280	3,063
Exchange adjustments		**(2)**	**(2)**		25	25
Charge for the year	**2,710**	**267**	**2,977**	745	317	1,062
Impairment losses	**253**	**85**	**338**		126	126
Impairment reversals				(42)		(42)
Transfers	**(365)**		**(365)**			
Reclassified as assets held for sale					(21)	(21)
Deletions	**(2,798)**	**(129)**	**(2,927)**	(409)	(186)	(595)
At 31 December	**877**	**2,762**	**3,639**	1,077	2,541	3,618
Net book amount at 31 December	**20,865**	**1,174**	**22,039**	23,434	1,198	24,632
Net book amount at 1 January	**23,434**	**1,198**	**24,632**	20,433	1,220	21,653

17. Investments in joint ventures

The significant joint ventures of the BP group at 31 December 2013 are shown in Note 38. Summarized financial information for the group s share of joint ventures is shown below. Balance sheet information shown below excludes data relating to joint ventures classified as assets held for sale as at the end of the period. Income statement information shown below includes data relating to joint ventures reclassified as assets held for sale during the period up until the date of reclassification. The group does not have any individually material joint ventures.

The following table provides aggregated summarized financial information relating to the group s share of joint ventures.

			$ million
	2013	2012	2011
Sales and other operating revenues	**12,507**	12,507	11,993
Profit before interest and taxation	**1,076**	778	1,315

Finance costs	**130**	113	115
Profit before taxation	**946**	665	1,200
Taxation	**499**	405	433
Profit for the year	**447**	260	767
Other comprehensive income	**38**	(52)	
Total comprehensive income	**485**	208	767
Non-current assets	**11,576**	11,147	
Current assets	**3,095**	2,931	
Total assets	**14,671**	14,078	
Current liabilities	**2,276**	2,350	
Non-current liabilities	**3,499**	3,379	
Total liabilities	**5,775**	5,729	
	8,896	8,349	
Group investment in joint ventures			
Group share of net assets (as above)	**8,896**	8,349	
Loans made by group companies to joint ventures	**303**	265	
	9,199	8,614	

Table of Contents

17. Investments in joint ventures continued

Transactions between the group and its joint ventures are summarized below.

$ million

Sales to joint ventures	**2013**		2012		2011	
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	**4,125**	**342**	4,272	379	3,196	423

$ million

Purchases from joint ventures	**2013**		2012		2011	
Product	**Purchases**	**Amount payable at 31 December**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**503**	**51**	1,107	116	1,165	62

The terms of the outstanding balances receivable from joint ventures 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. Dividends receivable are not included in the table above.

BP has commitments amounting to $21 million (2012 $53 million) in relation to contracts with joint ventures for the purchase of LNG, crude oil and oil products, refinery operating costs and storage and handling services. See Note 36 for further information on capital commitments relating to BP s investments in joint ventures.

18. Investments in associates

The following table provides aggregated financial information for the group s associates as it relates to the amounts recognized in the group income statement and on the group balance sheet.

$ million

	Earnings from associates after interest and tax			Investments in associates		
	2013	2012	2011	**2013**	2012	2011

Rosneft	**2,058**			**13,681**		
TNK-BP		2,986	4,185			10,013
Other associates	**684**	689	731	**2,955**	2,998	3,278
	2,742	3,675	4,916	**16,636**	2,998	13,291

The associate that is material to the group at 31 December 2013 is Rosneft (2012 TNK-BP). In 2013, BP concluded transactions to sell its 50% interest in TNK-BP to Rosneft and to increase BP s investment in Rosneft. BP and Rosneft announced heads of terms for this transaction on 22 October 2012, after which our investment in TNK-BP was classified as an asset held for sale and therefore equity accounting ceased. See below and Note 6 for further information. Other significant associates of the BP group at 31 December 2013 are shown in Note 38.

At 31 December 2013, and since the transaction described in Note 6 concluded on 21 March 2013, BP owned 19.75% of the voting shares of OJSC Oil Company Rosneft (Rosneft), a Russian oil and gas company. Rosneft shares are listed on the MICEX stock exchange in Moscow and its global depository receipts are listed on the London Stock Exchange. The Russian federal government, through its investment company OJSC Rosneftegaz, owned 69.5% of the voting shares of Rosneft at 31 December 2013.

BP uses the equity method of accounting for its investment in Rosneft because in management s judgement BP has significant influence over Rosneft, see Note 1 Interests in other entities significant estimate or judgement for further information.

Table of Contents

18. Investments in associates continued

The following table provides summarized financial information at 100% share relating to each of the group s material associates.

			$ million Gross amount
	2013	2012	2011
	Rosneft	TNK-BP[a]	TNK-BP
Sales and other operating revenues	**122,866**	49,350	60,200
Profit before interest and taxation	**14,106**	8,810	11,984
Finance costs	**1,337**	168	264
Profit before taxation	**12,769**	8,642	11,720
Taxation	**2,137**	1,958	2,666
Non-controlling interests	**213**	712	684
Profit for the year	**10,419**	5,972	8,370
Other comprehensive income	**(441)**	26	(77)
Total comprehensive income	**9,978**	5,998	8,293
Non-current assets	**149,149**		
Current assets	**48,775**		
Total assets	**197,924**		
Current liabilities	**43,175**		
Non-current liabilities	**83,458**		
Total liabilities	**126,633**		
Non-controlling interests	**2,020**		
	69,271		

[a] BP ceased equity accounting for TNK-BP on 22 October 2012. See Note 6 for further information.

The group received dividends of $456 million from Rosneft in 2013, net of withholding tax (2012 dividends of $709 million from TNK-BP and 2011 dividends of $3,747 million from TNK-BP).

Summarized financial information for the group s share of associates is shown below. Balance sheet information shown below does not include data relating to associates classified as assets held for sale as at the end of the period. Income statement and other comprehensive income information shown below includes data relating to associates classified as assets held for sale during the period prior to their classification as assets held for sale.

									$ million BP share
			2013			2012			2011
	Rosneft[a]	**Other**	**Total**	TNK-BP[b]	Other	Total	TNK-BP	Other	Total
Sales and other operating	**24,266**	**7,967**	**32,233**	24,675	11,965	36,640	30,100	12,145	42,245

revenues									
Profit before interest and taxation	**2,786**	**908**	**3,694**	4,405	906	5,311	5,992	958	6,950
Finance costs	**264**	**11**	**275**	84	16	100	132	13	145
Profit before taxation	**2,522**	**897**	**3,419**	4,321	890	5,211	5,860	945	6,805
Taxation	**422**	**213**	**635**	979	201	1,180	1,333	214	1,547
Non-controlling interests	**42**		**42**	356		356	342		342
Profit for the year	**2,058**	**684**	**2,742**	2,986	689	3,675	4,185	731	4,916
Other comprehensive income	**(87)**	**2**	**(85)**	13	(6)	7	(39)		(39)
Total comprehensive income	**1,971**	**686**	**2,657**	2,999	683	3,682	4,146	731	4,877
Non-current assets	**29,457**	**3,148**	**32,605**		3,270	3,270			
Current assets	**9,633**	**2,477**	**12,110**		2,399	2,399			
Total assets	**39,090**	**5,625**	**44,715**		5,669	5,669			
Current liabilities	**8,527**	**2,114**	**10,641**		2,126	2,126			
Non-current liabilities	**16,483**	**1,053**	**17,536**		1,290	1,290			
Total liabilities	**25,010**	**3,167**	**28,177**		3,416	3,416			
Non-controlling interests	**399**		**399**						
	13,681	**2,458**	**16,139**		2,253	2,253			
Group investment in associates									
Group share of net assets (as above)	**13,681**	**2,458**	**16,139**		2,253	2,253			
Loans made by group companies to associates		**497**	**497**		745	745			
	13,681	**2,955**	**16,636**		2,998	2,998			

[a] The fair value of BP s 19.75% stake in Rosneft was $15,937 million at 31 December 2013 based on the quoted market share price of $7.62 per share.

[b] BP ceased equity accounting for TNK-BP on 22 October 2012. See Note 6 for further information.

Table of Contents

18. Investments in associates continued

Transactions between the group and its associates are summarized below.

$ million

Sales to associates	2013		2012		2011	
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	**5,170**	**783**	3,771	401	3,855	393

$ million

Purchases from associates	2013		2012		2011	
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	**21,205**	**3,470**	9,135	932	8,159	815

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. Dividends receivable are not included in the table above.

The majority of the purchases from associates are crude oil and oil products purchased from Rosneft. BP has commitments amounting to $6,077 million (2012 $595 million) in relation to contracts with its associates for the purchase of crude oil and oil products, transportation and storage. See Note 36 for further information on capital commitments relating to BP s investments in associates.

19. Financial instruments and financial risk factors

The accounting classification of each category of financial instruments, and their carrying amounts, are set out below.

$ million

At 31 December 2013	Note	Loans and receivables	Available-for-sale financial assets	Held-to-maturity investments	At fair value through profit or loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
Financial assets								
	20		**291**					**291**

Other investments equity shares								
other	**20**		**1,167**		**574**			**1,741**
Loans		**979**						**979**
Trade and other receivables	**22**	**39,630**						**39,630**
Derivative financial instruments	**26**				**5,189**	**995**		**6,184**
Cash and cash equivalents	**23**	**19,153**	**2,267**	**1,100**				**22,520**
Financial liabilities								
Trade and other payables	**25**						**(48,072)**	**(48,072)**
Derivative financial instruments	**26**				**(4,159)**	**(388)**		**(4,547)**
Accruals							**(9,507)**	**(9,507)**
Finance debt	**27**						**(48,192)**	**(48,192)**
		59,762	**3,725**	**1,100**	**1,604**	**607**	**(105,771)**	**(38,973)**
At 31 December 2012								
Financial assets								
Other investments equity shares	20		1,433					1,433
other	20		1,005		585			1,590
Loans		889						889
Trade and other receivables	22	35,962						35,962
Derivative financial instruments	26				5,342	3,459		8,801
Cash and cash equivalents	23	15,128	4,507					19,635
Financial liabilities								
Trade and other payables	25						(44,405)	(44,405)
Derivative financial instruments	26				(5,093)	(288)		(5,381)
Accruals							(7,366)	(7,366)
Finance debt	27						(48,168)	(48,168)
		51,979	6,945		834	3,171	(99,939)	(37,010)

The fair value of finance debt is shown in Note 27. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

Financial risk factors

The group is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments including: market risks relating to commodity prices, foreign currency exchange rates, interest rates and equity prices; credit risk; and liquidity risk.

Table of Contents

19. Financial instruments and financial risk factors continued

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 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.

The group measures market risk exposure arising from its trading positions using value-at-risk techniques. These techniques make a statistical assessment of the market risk arising from possible future changes in market prices over a one-day holding period. The value-at-risk measure is supplemented by stress testing. 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.

In addition, the group has embedded derivatives relating to certain natural gas contracts. The net fair value of these contracts was a liability of $652 million at 31 December 2013 (2012 liability of $1,112 million). For these embedded derivatives the sensitivity of the net fair value to an immediate 10% favourable or adverse change in each key assumption is less than $100 million in each case.

(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.

Since BP has global operations, fluctuations in foreign currency exchange rates can have a significant effect 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 limit 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 managing 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 $400 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 26.

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. At 31 December 2013 the most significant open contracts in place were for $723 million sterling (2012 $853 million sterling).

For other UK, European and Australian operational requirements the group uses cylinders (purchased call and sold put options) and currency forwards to manage the estimated exposures on a 12-month rolling basis. At 31 December 2013, the open positions relating to cylinders consisted of receive sterling, pay US dollar cylinders for $2,770 million (2012 $2,886 million); receive euro, pay US dollar cylinders for $962 million (2012 $1,636 million); receive Australian dollar, pay US dollar cylinders for $401 million (2012 $522 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 2013, the total foreign currency net borrowings not swapped into US dollars amounted to $665 million (2012 $364 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.

Table of Contents

19. Financial instruments and financial risk factors continued

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 at 31 December 2013 was 65% of total finance debt outstanding (2012 65%). The weighted average interest rate on finance debt at 31 December 2013 was 2% (2012 2%) and the weighted average maturity of fixed rate debt was four years (2012 four 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 one percentage point on 1 January 2014, it is estimated that the group s finance costs for 2014 would increase by approximately $312 million (2012 $311 million increase in 2013).

(iv) Equity price risk

The group holds equity investments, typically 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.

At 31 December 2013 the group had no significant exposure to the price of quoted equity instruments. At 31 December 2012, an increase or decrease of 10% in quoted equity prices would have resulted in an immediate credit or charge to other comprehensive income of $1,502 million. At 31 December 2012, 82% 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 was concentrated on changes in the share price of this equity in particular. The sensitivity analysis at 31 December 2012 includes the impact of a change in the share price on the valuation of the contracts to acquire Rosneft shares accounted for as cash flow hedge derivatives.

(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. Credit exposure also exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2013 were $199 million (2012 $237 million) in respect of liabilities of joint ventures and associates and $305 million (2012 $717 million) in respect of liabilities of other third parties.

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 maximum credit exposure associated with financial assets is equal to the carrying amount. The group does not aim to remove credit risk entirely but expects to experience a certain level of credit losses. As at 31 December 2013, the group had in place credit enhancements designed to mitigate approximately $13 billion of credit risk (2012 $12 billion). 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.

For the contracts comprising derivative financial instruments in an asset position at 31 December 2013 it is estimated that over 80% (2012 over 70%, excluding the contracts with Rosneft accounted for as derivatives) 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 2013, 92% of the cash and cash equivalents balance was deposited with financial institutions rated at least A- by Standard & Poor s and Fitch, and A3 by Moody s. Of the total cash and cash equivalents held at year end, collateral of $5,450 million was held by third-party custodians in tri-partite repurchase agreements, which would only be released to BP in the event of repayment default by the borrower.

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% (2012 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 $2.3 billion (see page 241), 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	**2013**	2012
Neither impaired nor past due	**37,201**	33,053
Impaired (net of provision)	**27**	80
Not impaired and past due in the following periods		
within 30 days	**1,054**	1,337
31 to 60 days	**249**	286
61 to 90 days	**216**	225
over 90 days	**883**	981
	39,630	35,962

Movements in the impairment provision for trade receivables are shown in Note 24.

Financial instruments subject to offsetting, enforceable master netting arrangements and similar agreements

The following table shows the gross amounts of recognized financial assets and liabilities (i.e. before offsetting) and the amounts offset in the balance sheet. Financial assets and liabilities are only offset when the group currently has a legally enforceable right to set off the recognized amounts and the group intends to either settle on a net basis or realize the asset and settle the liability simultaneously. A right of set off is the group s legal right to settle an amount payable to a creditor by applying against it an amount receivable from the same counterparty. The relevant legal jurisdiction and laws applicable to the relationships between the parties need to be considered when assessing whether a current legally enforceable right to set off exists.

Table of Contents

19. Financial instruments and financial risk factors continued

Furthermore, amounts which cannot be offset under IFRS, but which could be settled net under the terms of master netting agreements if certain conditions arise, and collateral received or pledged, are also shown in the table to show the total net exposure of the group.

$ million

At 31 December 2013	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the balance sheet	Related amounts not set off in the balance sheet: Master netting arrangements	Related amounts not set off in the balance sheet: Cash collateral (received) pledged	Net amount
Derivative assets	**7,271**	**(1,563)**	**5,708**	**(344)**	**(231)**	**5,133**
Derivative liabilities	**(5,457)**	**1,563**	**(3,894)**	**344**		**(3,550)**
Trade receivables	**11,034**	**(7,744)**	**3,290**	**(1,287)**	**(264)**	**1,739**
Trade payables	**(10,619)**	**7,744**	**(2,875)**	**1,287**		**(1,588)**
At 31 December 2012						
Derivative assets	9,291	(1,870)	7,421	(754)	(175)	6,492
Derivative liabilities	(6,117)	1,870	(4,247)	754		(3,493)
Trade receivables	8,829	(6,368)	2,461	(578)	(176)	1,707
Trade payables	(9,330)	6,368	(2,962)	578		(2,384)

(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.

The group has in place a European Debt Issuance Programme (DIP) under which the group may raise up to $30 billion of debt for maturities of one month or longer. At 31 December 2013, the amount drawn down against the DIP was $13,854 million (2012 $14,043 million). Since 5 February 2013, the group has had a US shelf registration with a limit of $30 billion. This was converted from an unlimited shelf registration following the approval in December 2012 of the settlement with the US Securities and Exchange Commission in respect of Gulf of Mexico oil spill related claims. Amounts drawn down since conversion total $6.9 billion. In addition, the group has an Australian Note Issuance Programme of A$5 billion, and as at 31 December 2013 the amount drawn down was A$800 million (2012 A$500 million).

The group s long-term credit ratings are A (positive outlook) from Standard & Poor s, and A2 (stable outlook) from Moody s Investor Services, both remaining unchanged during 2013.

During 2013, $8.6 billion of long-term taxable bonds were issued with terms ranging from 18 months to 10 years. 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 $22.5 billion at 31 December 2013, primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice (2012 $19.6 billion). At 31 December 2013, the group had substantial amounts of undrawn borrowing facilities available, consisting of $7,375 million of standby facilities, of which $6,975 million is available to draw and repay until the first half of 2018, and $400 million is available to draw and repay until April 2016. These facilities were renegotiated during 2013 with 26 international banks, and borrowings under them would be at pre-agreed rates.

The group also has committed letter of credit (LC) facilities totalling $7,475 million with a number of banks, allowing LCs to be issued for a maximum one-year duration. There were also uncommitted secured LC facilities in place at 31 December 2013 for $2,410 million, which are secured against inventories or receivables when utilized. The facilities only terminate by either party giving a stipulated termination notice to the other.

The amounts shown for finance debt in the table below include future minimum lease payments with respect to finance leases. The table also shows the timing of cash outflows relating to trade and other payables and accruals.

$ million

				2013				2012
	Trade and other payables	**Accruals**	**Finance debt**	**Interest relating to finance debt**	Trade and other payables	Accruals	Finance debt	Interest relating to finance debt
Within one year	**43,790**	**8,960**	**7,381**	**885**	42,512	6,875	9,401[a]	893
1 to 2 years	**1,007**	**207**	**6,630**	**752**	903	136	5,906	755
2 to 3 years	**822**	**66**	**6,720**	**621**	434	80	5,902	634
3 to 4 years	**761**	**73**	**5,828**	**498**	373	52	6,024	510
4 to 5 years	**1,405**	**37**	**5,279**	**388**	71	83	5,797	388
5 to 10 years	**207**	**113**	**15,933**	**809**	79	84	14,790	885
Over 10 years	**80**	**51**	**421**	**119**	33	56	348	50
	48,072	**9,507**	**48,192**	**4,072**	44,405	7,366	48,168	4,115

[a] In addition, current finance debt on the group balance sheet at 31 December 2012 included $632 million in respect of cash deposits received for disposals which completed in 2013.

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 26. 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 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

Table of Contents

19. Financial instruments and financial risk factors continued

settlement amounts (inflows) for the receive leg of derivatives that are settled separately from the pay leg, which amount to $12,222 million at 31 December 2013 (2012 $8,620 million) to be received on the same day as the related cash outflows.

		$ million
	2013	2012
Within one year	**1,095**	1,356
1 to 2 years	**293**	1,107
2 to 3 years	**2,959**	295
3 to 4 years	**2,577**	1,261
4 to 5 years	**1,505**	2,577
5 to 10 years	**3,835**	1,903
	12,264	8,499

20. Other investments

					$ million
			2013		2012
		Current	**Non-current**	Current	Non-current
Equity investments	listed		**3**		1,182
	unlisted		**288**		251
Repurchased gas pre-paid bonds		**276**	**408**	303	686
Contingent consideration		**186**	**292**		
Other		**5**	**574**	16	585
		467	**1,565**	319	2,704

At 31 December 2012 the group s 1.25% stake in Rosneft was the most significant listed investment, with a fair value of $1,179 million.

BP 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.

At 31 December 2013 the group had contingent consideration receivable in respect of the disposal of the Devenick field, classified as an available-for-sale financial asset.

Other non-current investments at 31 December 2013 include $574 million relating to life insurance policies (2012 $585 million). The life insurance policies have been designated as financial assets at fair value through profit and loss and their valuation methodology is in level 3 of the fair value hierarchy. Fair value losses of $4 million were recognized in the income statement (2012 $70 million gain and 2011 $21 million gain).

21. Inventories

		$ million
	2013	2012
Crude oil	**10,190**	9,123
Natural gas	**235**	187
Refined petroleum and petrochemical products	**15,427**	15,465
	25,852	24,775
Supplies	**2,735**	2,428
	28,587	27,203
Trading inventories	**644**	1,000
	29,231	28,203
Cost of inventories expensed in the income statement	**298,351**	292,774

The inventory valuation at 31 December 2013 is stated net of a provision of $322 million (2012 $124 million) to write inventories down to their net realizable value. The net charge to the income statement in the year in respect of inventory net realizable value provisions was $195 million (2012 $28 million credit).

Trading inventories are valued using quoted benchmark bid prices adjusted as appropriate for location and quality differentials. As such they are predominantly categorized within level 2 of the fair value hierarchy.

Inventories with a carrying amount of $227 million (2012 $64 million) have been pledged as security for certain of the group s liabilities at 31 December 2013.

Table of Contents

22. Trade and other receivables

				$ million
		2013		2012
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**28,868**	**183**	26,485	151
Amounts receivable from joint ventures and associates	**1,213**	**47**	871	102
Other receivables	**6,594**	**2,725**	5,683	2,670
	36,675	**2,955**	33,039	2,923
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**2,457**	**2,442**	4,178	2,264
Other receivables	**699**	**588**	394	774
	3,156	**3,030**	4,572	3,038
	39,831	**5,985**	37,611	5,961

[a] See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 19 for further information.

Receivables with a carrying amount of $236 million (2012 $12 million) have been pledged as security for certain of the group s liabilities at 31 December 2013.

23. Cash and cash equivalents

		$ million
	2013	2012
Cash at bank and in hand	**6,907**	5,885
Term bank deposits	**12,246**	9,243
Cash equivalents	**3,367**	4,507
	22,520	19,635

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; money market funds and commercial paper. 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 2013 includes $1,626 million (2012 $1,544 million) that is restricted. Included in restricted cash at 31 December 2012 was $709 million relating to the dividend received from TNK-BP in December 2012 which remained restricted until completion of the sale of BP s interest in TNK-BP to Rosneft, which occurred in the first quarter of 2013. See Note 6 for further information. The remaining restricted cash balances relate largely to amounts required to cover initial margin on trading exchanges.

24. Valuation and qualifying accounts

$ million

	2013		2012		2011	
	Accounts receivable	**Fixed asset investments**	Accounts receivable	Fixed asset investments	Accounts receivable	Fixed asset investments
At 1 January	**489**	**349**	332	643	428	540
Charged to costs and expenses	**82**	**4**	240	196	115	111
Charged to other accounts[a]	**(4)**	**4**	7	18	(16)	(3)
Deductions	**(224)**	**(189)**	(90)	(508)	(195)	(5)
At 31 December	**343**	**168**	489	349	332	643

[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.

25. Trade and other payables

$ million

	2013		2012	
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**28,926**		29,920	
Amounts payable to joint ventures and associates	**3,576**	**47**	1,105	102
Other payables	**11,288**	**4,235**	11,487	1,791
	43,790	**4,282**	42,512	1,893
Non-financial liabilities				
Other payables	**3,369**	**474**	4,161	399
	47,159	**4,756**	46,673	2,292

Trade and other payables are predominantly non-interest bearing. See Note 19 for further information.

Table of Contents

26. Derivative financial instruments

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. An outline of the group s financial risks and the objectives and policies pursued in relation to those risks is set out in Note 19. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts.

The fair values of derivative financial instruments at 31 December are set out below.

				$ million
		2013		2012
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**192**	**(111)**	175	(189)
Oil price derivatives	**810**	**(806)**	841	(707)
Natural gas price derivatives	**2,840**	**(2,029)**	3,536	(2,496)
Power price derivatives	**871**	**(560)**	719	(589)
Other derivatives	**475**		71	
	5,188	**(3,506)**	5,342	(3,981)
Embedded derivatives				
Commodity price contracts	**1**	**(653)**		(1,112)
	1	**(653)**		(1,112)
Cash flow hedges				
Equity price derivatives			1,339	
Currency forwards, futures and cylinders	**129**	**(30)**	51	(41)
Cross-currency interest rate swaps		**(69)**	1	
	129	**(99)**	1,391	(41)
Fair value hedges				
Currency forwards, futures and swaps	**340**	**(154)**	875	(247)
Interest rate swaps	**526**	**(135)**	1,193	
	866	**(289)**	2,068	(247)
	6,184	**(4,547)**	8,801	(5,381)
Of which current	**2,675**	**(2,322)**	4,507	(2,658)
non-current	**3,509**	**(2,225)**	4,294	(2,723)

Exchange traded derivatives are valued using closing prices provided by the exchange as at the balance sheet date. These derivatives are categorized within level 1 of the fair value hierarchy. Over-the-counter (OTC) financial swaps and physical commodity sale and purchase contracts are generally valued using readily available information in the public markets and quotations provided by brokers and price index developers. These quotes are corroborated with market data and are categorized within level 2 of the fair value hierarchy.

In certain less liquid markets, or for longer-term contracts, forward prices are not as readily available. In these circumstances, OTC financial swaps and physical commodity sale and purchase contracts are valued using internally developed methodologies that consider historical relationships between various commodities, and that result in management s best estimate of fair value. These contracts are categorized within level 3 of the fair value hierarchy.

Financial OTC and physical commodity options are valued using industry standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and contractual prices for the underlying instruments, as well as other relevant economic factors. The degree to which these inputs are observable in the forward markets determines whether the option is categorized within level 2 or level 3 of the fair value hierarchy.

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 19.

Table of Contents

26. Derivative financial instruments continued

The following tables show further information on the fair value of derivatives and other financial instruments held for trading purposes.

Derivative assets held for trading have the following fair values and maturities.

							$ million
							2013
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**143**		**21**			**28**	**192**
Oil price derivatives	**694**	**78**	**23**	**13**	**2**		**810**
Natural gas price derivatives	**1,034**	**526**	**334**	**192**	**154**	**600**	**2,840**
Power price derivatives	**528**	**202**	**81**	**22**	**8**	**30**	**871**
Other derivatives	**102**		**93**	**147**	**66**	**67**	**475**
	2,501	**806**	**552**	**374**	**230**	**725**	**5,188**

							$ 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
Other derivatives	71						71
	2,755	1,014	570	342	175	486	5,342

At 31 December 2013 the group had contingent consideration receivable in respect of a business disposal. The sale agreement contained an embedded derivative the whole agreement has, consequently, been designated at fair value through profit or loss and shown within other derivatives held for trading, and falls within level 3 of the fair value hierarchy. The valuation depends on refinery throughput and future margins. At 31 December 2012, other derivatives related to the anticipated transaction with Rosneft see Cash flow hedges below for further information.

Derivative liabilities held for trading have the following fair values and maturities.

	$ million
	2013
	Total

	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	
Currency derivatives	**(111)**						**(111)**
Oil price derivatives	**(620)**	**(100)**	**(42)**	**(31)**	**(13)**		**(806)**
Natural gas price derivatives	**(778)**	**(319)**	**(157)**	**(110)**	**(102)**	**(563)**	**(2,029)**
Power price derivatives	**(400)**	**(99)**	**(48)**	**(13)**			**(560)**
	(1,909)	**(518)**	**(247)**	**(154)**	**(115)**	**(563)**	**(3,506)**

							$ 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)

Table of Contents

26. 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. This information is presented on a gross basis, that is, before netting by counterparty.

$ million

							2013
	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	**100**						**100**
Level 2	**3,118**	**981**	**399**	**83**	**20**	**30**	**4,631**
Level 3	**389**	**183**	**252**	**291**	**210**	**695**	**2,020**
	3,607	**1,164**	**651**	**374**	**230**	**725**	**6,751**
Less: netting by counterparty	**(1,106)**	**(358)**	**(99)**				**(1,563)**
	2,501	**806**	**552**	**374**	**230**	**725**	**5,188**
Fair value of derivative liabilities							
Level 1	**(87)**						**(87)**
Level 2	**(2,790)**	**(733)**	**(215)**	**(36)**	**(15)**	**(31)**	**(3,820)**
Level 3	**(138)**	**(143)**	**(131)**	**(118)**	**(100)**	**(532)**	**(1,162)**
	(3,015)	**(876)**	**(346)**	**(154)**	**(115)**	**(563)**	**(5,069)**
Less: netting by counterparty	**1,106**	**358**	**99**				**1,563**
	(1,909)	**(518)**	**(247)**	**(154)**	**(115)**	**(563)**	**(3,506)**
Net fair value	**592**	**288**	**305**	**220**	**115**	**162**	**1,682**

$ 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

Level 3 derivatives

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	Other	Total
Net fair value of contracts at 1 January 2013	**105**	**304**	**(43)**	**71**	**437**
Gains (losses) recognized in the income statement	**(47)**	**62**	**81**		**96**
Purchases	**110**	**1**			**111**
New contracts				**475**	**475**
Settlements	**(143)**	**(52)**	**10**	**(71)**	**(256)**
Transfers out of level 3	**(43)**	**(1)**	**36**		**(8)**
Exchange adjustments		**(1)**	**2**		**1**
Net fair value of contracts at 31 December 2013	**(18)**	**313**	**86**	**475**	**856**

Table of Contents

26. Derivative financial instruments continued

$ million

	Oil price	Natural gas price	Power price	Other	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

US natural gas price derivatives are valued using observable market data for maturities up to 60 months in basis locations that trade at a premium or discount to the NYMEX Henry Hub price, and using internally developed price curves based on economic forecasts for periods beyond that time. At 31 December 2013, the US natural gas derivatives in level 3 of the fair value hierarchy had a net fair value of $351 million. Of this amount, $71 million (asset of $598 million and liability of $527 million) depends on level 3 inputs, with the remainder valued using level 2 inputs. The significant unobservable inputs for fair value measurements categorized within level 3 of the fair value hierarchy for the year ended 31 December 2013 are presented below.

	Unobservable inputs	**Range $/mmBtu**	**Weighted average $/mmBtu**
Natural gas price contracts	Long-dated market price	3.15-6.71	4.63

If the natural gas prices after 2018 were 10% higher (lower), this would result in a decrease (increase) in derivative assets of $82 million, and decrease (increase) in derivative liabilities of $78 million, and a net decrease (increase) in profit before tax of $4 million.

Derivative gains and losses

Gains and losses relating to derivative contracts are included within sales and other operating revenues and 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 (excluding gains and losses on realized physical derivative contracts that have been reflected gross in the income statement within sales and purchases) was a gain of $587 million (2012 $411 million net loss and 2011 $216 million net gain[a]).

[a] The comparative amounts for 2012 and 2011 have been amended and now reflect only the margin on derivative contracts that have been reflected net within the income statement.

Embedded derivatives

The group is a party to contracts containing 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.

Key information on the natural gas contracts is given below.

At 31 December	**2013**	2012
Remaining contract terms	**1 year and 5 months to 4 years and 9 months**	2 years and 5 months to 5 years and 9 months
Contractual/notional amount	**153 million therms**	117 million therms

The commodity price embedded derivatives relate to natural gas contracts and are categorized in levels 2 and 3 of the fair value hierarchy. The contracts in level 2 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, the price curves 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. These valuations are categorized in level 3. Transfers from level 3 to level 2 occur when the valuation no longer depends significantly on extrapolated or interpolated data. Valuations use observable market data for maturities up to 36 months, and internally developed price curves based on economic forecasts for periods beyond that time.

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

	2013 Commodity price	2012 Commodity price
Net fair value of contracts at 1 January	**(1,112)**	(1,417)
Settlements	**316**	375
Gains (losses) recognized in the income statement	**142**	(6)
Transfers out of level 3	**258**	
Exchange adjustments	**17**	(64)
Net fair value of contracts at 31 December	**(379)**	(1,112)

Table of Contents

26. Derivative financial instruments continued

The fair value gain (loss) on embedded derivatives is shown below.

			$ million
	2013	2012	2011
Commodity price embedded derivatives	**459**	347	190
Other embedded derivatives			(122)
Fair value gain (loss)	**459**	347	68

Cash flow hedges

At 31 December 2013, 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. Note 19 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. The pre-tax amount reclassified from equity and recognized in the income statement in production and manufacturing expenses was a loss of $4 million (2012 $62 million loss and 2011 $195 million gain). The amount reclassified from equity and recognized in the carrying amount of non-financial assets was a loss of $17 million (2012 $19 million loss and 2011 $13 million gain). The amounts remaining in equity at 31 December 2013 in relation to these cash flow hedges consist of deferred gains of $85 million maturing in 2014, deferred losses of $23 million maturing in 2015 and deferred gains of $10 million maturing in 2016 and beyond.

At 31 December 2012, BP had entered into three agreements to sell its 50% interest in TNK-BP and acquire 18.5% of Rosneft, as described in Note 6. During the period from signing until completion on 21 March 2013, these agreements represented derivative financial instruments that were required to be measured at fair value. BP 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 were recognized in other comprehensive income. The third agreement, under which BP sold its 50% interest in TNK-BP in exchange for cash and a 3.04% shareholding in Rosneft, was also a derivative financial instrument, but its fair value could not 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 related to the fair value of the cash flow hedge derivatives. The derivatives measured at fair value at 31 December 2012 were categorized in level 3 of the fair value hierarchy using inputs that included the quoted Rosneft share price. During 2013, a charge of $2,061 million was recognized in other comprehensive income in relation to these agreements and $4 million was recognized in the income statement. The resulting cumulative charge of $651 million recognized in other comprehensive income would only be recognized in the income statement if the investment in Rosneft were either sold or impaired. The cash flow hedge derivatives were valued using the quoted Rosneft share price at the time the deal completed, of $7.60 per share.

Fair value hedges

At 31 December 2013, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk on fixed rate debt issued by the group. The effectiveness of each hedge relationship is quantitatively assessed and demonstrated to continue to be highly effective. The loss on the hedging derivative instruments recognized in the income statement in 2013 was $1,240 million (2012 $536 million gain and 2011 $328 million gain) offset by a gain on the fair value of the finance debt of $1,228 million (2012 $537 million loss and 2011 $327 million loss).

The interest rate and cross-currency interest rate swaps mature within one to 10 years, with an average maturity of four to five years (2012 four to five years) and are used to convert sterling, euro, Swiss franc, Australian dollar, Canadian dollar and Hong Kong dollar denominated borrowings primarily into US dollar floating rate debt. Note 19 outlines the group s approach to interest rate and currency risk management.

27. Finance debt

						$ million
			2013			2012
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**7,340**	**40,317**	**47,657**	9,372	38,412	47,784
Net obligations under finance leases	**41**	**494**	**535**	29	355	384
	7,381	**40,811**	**48,192**	9,401	38,767	48,168
Disposal deposits				632		632
	7,381	**40,811**	**48,192**	10,033	38,767	48,800

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

$6,230 million (2012 $6,240 million) and issued commercial paper of $1,050 million (2012 $3,028 million). Finance debt does not include accrued interest, which is reported within other payables.

Deposits for disposal transactions of $632 million were included in current finance debt at 31 December 2012. This unsecured debt was extinguished on completion of the transactions in 2013. There were no deposits for disposal transactions included within finance debt at 31 December 2013.

At 31 December 2013, $141 million (2012 $142 million) of finance debt was secured by the pledging of assets. The remainder of finance debt was unsecured.

Table of Contents

27. Finance debt continued

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
						2013
US dollar	**3**	**4**	**16,405**	**1**	**29,740**	**46,145**
Euro	**5**	**30**	**157**	**2**	**1,396**	**1,553**
Other currencies	**4**	**7**	**454**	**2**	**40**	**494**
			17,016		**31,176**	**48,192**
						2012
US dollar	3	4	16,744	1	26,208	42,952
Euro	5	2	20	1	4,854	4,874
Other currencies	4	11	255	3	87	342
			17,019		31,149	48,168

The euro debt not swapped to US dollar is naturally hedged with respect to the foreign currency risk by holding equivalent euro cash and cash equivalent amounts.

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 12 months from 31 December 2013, 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 values of the group s long-term borrowings are principally determined using quoted prices in active markets (and so fall within level 1 of the fair value hierarchy) or, where quoted prices are not available, quoted prices for similar instruments in active markets. The fair value of the group s finance lease obligations is estimated using discounted cash flow analyses based on the group s current incremental borrowing rates for similar types and maturities of borrowing.

				$ million
	2013			2012
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**1,110**	**1,110**	3,131	3,131
Long-term borrowings	**47,398**	**46,547**	45,969	44,653
Net obligations under finance leases	**654**	**535**	520	384
Total finance debt	**49,162**	**48,192**	49,620	48,168

28. 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. We intend 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, plus the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is 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 2013, the net debt ratio was 16.2% (2012 18.7%).

During 2013, the company repurchased 753 million shares for a total amount of $5.5 billion, including fees and stamp duty, as part of its share buyback programme announced on 22 March 2013. During 2012, 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	**2013**	2012
Gross debt	**48,192**	48,800
Fair value (asset) liability of hedges related to finance debt	**(477)**	(1,700)
	47,715	47,100
Less: cash and cash equivalents	**22,520**	19,635
Net debt	**25,195**	27,465
Equity	**130,407**	119,752
Net debt ratio	**16.2%**	18.7%

Table of Contents

28. Capital disclosures and analysis of changes in net debt continued

An analysis of changes in net debt is provided below.

$ million

Movement in net debt	2013 Finance debt[a]	2013 Cash and cash equivalents	2013 Net debt	2012 Finance debt[a]	2012 Cash and cash equivalents	2012 Net debt
At 1 January	**(47,100)**	**19,635**	**(27,465)**	(43,075)	14,177	(28,898)
Exchange adjustments	**(219)**	**40**	**(179)**	(75)	64	(11)
Net cash flow	**(836)**	**2,845**	**2,009**	(3,244)	5,394	2,150
Movement in finance debt relating to investing activities[b]	**632**		**632**	(602)		(602)
Other movements	**(192)**		**(192)**	(104)		(104)
At 31 December	**(47,715)**	**22,520**	**(25,195)**	(47,100)	19,635	(27,465)

[a] Including the fair value of associated derivative financial instruments.
[b] See Note 27 for further information.

29. Provisions

$ million

	Decommissioning	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Other	Total
At 1 January 2013	**17,374**	**3,631**	**345**	**10,251**	**3,510**	**2,872**	**37,983**
Exchange adjustments	**(37)**	**(7)**		**5**		**14**	**(25)**
New or increased provisions	**2,092**	**472**	**(66)**	**2,466**		**464**	**5,428**
Derecognition of provisions for items that cannot be reliably estimated				**(379)**			**(379)**
Write-back of unused provisions	**(2)**	**(52)**		**(38)**		**(210)**	**(302)**
Transfer between categories of provision		**47**	**(47)**				
Unwinding of discount	**110**	**11**		**10**		**16**	**147**
Change in discount rate	**(1,602)**	**(41)**		**(20)**		**(13)**	**(1,676)**
Utilization	**(500)**	**(695)**	**(143)**	**(3,451)**		**(230)**	**(5,019)**

Reclassified to other payables				(3,933)			(3,933)
Deletions	(230)	(1)				(33)	(264)
At 31 December 2013	**17,205**	**3,365**	**89**	**4,911**	**3,510**	**2,880**	**31,960**
Of which current	**866**	**769**	**84**	**2,725**		**601**	**5,045**
non-current	**16,339**	**2,596**	**5**	**2,186**	**3,510**	**2,279**	**26,915**
Of which Gulf of Mexico oil spill		**1,590**	**89**	**4,157**	**3,510**		**9,346**

Further information on the financial impacts of the Gulf of Mexico oil spill is provided in Note 2.

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 1% (2012 0.5%). The amount provided in the year for new or increased decommissioning provisions was $2,092 million (2012 $3,766 million). 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 1% (2012 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 2013 are provisions for deferred employee compensation of $602 million (2012 $618 million). These provisions are discounted using either a nominal discount rate of 3.25% (2012 2.5%) or a real discount rate of 1% (2012 0.5%), as appropriate.

30. 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 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. This pension plan is governed by a trustee board composed of four member-nominated and four company-nominated representatives, an independent chairman, an independent director and a chief executive officer appointed by the chairman. The trustee board is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as investment policies of the plan.

Table of Contents

30. Pensions and other post-retirement benefits continued

The UK plan is closed to new joiners but remains open to ongoing accrual for current members. New joiners in the UK are eligible for membership of 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 joiners. Retired US employees typically take their pension benefit in the form of a lump sum payment. The plan s assets are overseen by a fiduciary investment committee composed of seven company employees appointed by the appointing officer, who is the president of BP Corporation North America Inc. The investment committee is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as the investment policies, of the plan. 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 2013, contributions of $597 million (2012 $884 million and 2011 $429 million) and $386 million (2012 $153 million and 2011 $777 million) were made to the UK plans and US plans respectively. In addition, contributions of $289 million (2012 $238 million and 2011 $223 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2014 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.

For the primary UK plan there is an agreement between the group and the trustee under which contributions are determined annually based on the funding level of the plan. Under this agreement a proportion of any deficit and the service cost is funded in the following year. Contributions in the US are determined by legislation and are supplemented by discretionary contributions.

Certain group companies, principally in the US, provide post-retirement healthcare and life insurance benefits to retired employees and their 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 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 2013. 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 to estimate 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 and pension expense for the following year.

									%
Financial assumptions used to determine benefit obligation	**2013**	2012	UK	**2013**	2012	US	**2013**	2012	Other

			2011			2011			2011
Discount rate for pension plan liabilities	**4.6**	4.4	4.8	**4.3**	3.2	4.3	**3.9**	3.6	4.7
Discount rate for other post-retirement benefit plan liabilities	**n/a**	n/a	n/a	**4.5**	3.7	4.5	**n/a**	n/a	n/a
Rate of increase in salaries	**5.1**	4.9	5.1	**3.9**	4.2	3.7	**3.7**	3.7	3.7
Rate of increase for pensions in payment	**3.3**	3.1	3.2				**1.7**	1.7	1.7
Rate of increase in deferred pensions	**3.3**	3.1	3.2				**1.3**	1.2	1.2
Inflation for pension plan liabilities	**3.3**	3.1	3.2	**2.1**	2.4	1.9	**2.2**	2.2	2.2

Financial assumptions used to determine benefit expense			UK			US			Other
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Discount rate for pension plan service cost	**4.4**	4.8	5.5	**3.2**	4.3	4.7	**3.6**	4.7	5.3
Discount rate for pension plan other finance expense	**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 plan service cost	**n/a**	n/a	n/a	**3.7**	4.5	5.3	**n/a**	n/a	n/a
Inflation for pension plan service cost	**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.

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[a]
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Life expectancy at age 60 for a male currently aged 60	**27.8**	27.7	27.6	**24.9**	24.9	24.8	**23.3**	23.1	23.0
Life expectancy at age 60 for a male currently aged 40	**30.7**	30.6	30.5	**26.4**	26.3	26.3	**26.1**	26.0	25.8
Life expectancy at age 60 for a female currently aged 60	**29.5**	29.4	29.3	**26.5**	26.4	26.4	**27.8**	27.7	27.5
Life expectancy at age 60 for a female currently aged 40	**32.2**	32.1	32.0	**27.3**	27.3	27.3	**30.5**	30.3	30.2

[a] Minor amendments have been made to comparative amounts.

30. Pensions and other post-retirement benefits continued

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:

			%
	2013	2012	2011
First year s US healthcare cost trend rate	**7.3**	7.3	7.6
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2021**	2020	2020

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 current long-term asset allocation policy for the major plans is as follows:

			%
Asset category	UK	US	Other
Total equity	**70**	**60**	**17-65**
Bonds/cash	**23**	**40**	**25-78**
Property/real estate	**7**		**0-10**

The group s main pension plans do not invest directly in either securities or property/real estate of the company or of any subsidiary. Some of the group s pension plans use derivative financial instruments as part of their asset mix to manage the level of risk.

For the primary UK pension plan there is an agreement with the trustee to reduce the proportion of plan assets held as equities and increase the proportion held as bonds at certain market trigger points, over time, with a view to better matching the pension liabilities. During 2013 the first trigger point was reached. There is a similar agreement in place in the US where trigger points were reached in 2011 and 2013.

BP s main plans in the UK and US do not currently follow a liability driven investment (LDI) approach, a form of investing designed to match the movement in pension plan assets with the movement in projected benefit obligations over time.

Table of Contents

30. Pensions and other post-retirement benefits continued

The fair values of the various categories of assets held by the defined benefit plans at 31 December are presented in the table below, including the effects of derivative financial instruments. Movements in the fair value of plan assets during the year are shown in detail in the table on page 182.

$ million

	UK pension plans[a]	US pension plans[b]	US other post-retirement benefit plans	Other plans	Total
Fair value of pension plan assets					
At 31 December 2013					
Listed equities developed markets	**17,341**	**3,260**		**913**	**21,514**
emerging markets	**2,290**	**308**		**84**	**2,682**
Private equity	**2,907**	**1,432**		**6**	**4,345**
Government issued nominal bonds	**549**	**1,259**		**1,258**	**3,066**
Index-linked bonds	**787**			**69**	**856**
Corporate bonds	**4,427**	**1,323**		**982**	**6,732**
Property	**2,200**	**6**		**134**	**2,340**
Cash	**855**	**135**		**278**	**1,268**
Other	**160**	**55**		**113**	**328**
	31,516	**7,778**		**3,837**	**43,131**
At 31 December 2012					
Listed equities developed markets	15,659	3,622		844	20,125
emerging markets	1,074	341		89	1,504
Private equity	2,879	1,468		7	4,354
Government issued nominal bonds	544	904		1,042	2,490
Index-linked bonds	491			78	569
Corporate bonds	3,850	1,255		766	5,871
Property	1,783	5		139	1,927
Cash	1,000	86	1	321	1,408
Other	66	105		247	418
	27,346	7,786	1	3,533	38,666
At 31 December 2011					
Listed equities developed markets	13,622	3,328		754	17,704
emerging markets	890	299		69	1,258
Private equity	2,690	1,407		8	4,105
Government issued nominal bonds	513	733		993	2,239
Index-linked bonds	390			123	513
Corporate bonds	3,238	1,289		724	5,251

Property	1,710	4		117	1,831
Cash	470	88	4	326	888
Other	64	56		172	292
	23,587	7,204	4	3,286	34,081

[a] Bonds held by the UK pension fund are typically denominated in sterling. Property held by the UK pension fund is in the United Kingdom.

[b] Bonds held by the US pension fund are typically denominated in US dollars.

Table of Contents

30. Pensions and other post-retirement benefits continued

					$ million 2013
	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]	497	358	49	177	1,081
Past service cost[b]	(22)	(49)		27	(44)
Settlement				(1)	(1)
Operating charge relating to defined benefit plans	475	309	49	203	1,036
Payments to defined contribution plans	24	223		53	300
Total operating charge	499	532	49	256	1,336
Interest income on plan assets	(1,139)	(240)		(130)	(1,509)
Interest on plan liabilities	1,221	305	101	362	1,989
Other finance expense	82	65	101	232	480
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets[a]	2,671	730		114	3,515
Change in financial assumptions underlying the present value of the plan liabilities	60	1,054	106	283	1,503
Change in demographic assumptions underlying the present value of the plan liabilities		14		(65)	(51)
Experience gains and losses arising on the plan liabilities	41	(205)	(44)	5	(203)
Remeasurements recognized in other comprehensive income	2,772	1,593	62	337	4,764
Movements in benefit obligation during the year					
Benefit obligation at 1 January	29,259	10,029	2,845	10,148	52,281
Exchange adjustments	705			132	837
Operating charge relating to defined benefit plans	475	309	49	203	1,036
Interest cost	1,221	305	101	362	1,989
Contributions by plan participants[c]	37			13	50
Benefit payments (funded plans)[d]	(1,087)	(1,364)	(1)	(192)	(2,644)
Benefit payments (unfunded plans)[d]	(4)	(52)	(233)	(395)	(684)
Disposals	(9)		(61)	(13)	(83)
Remeasurements	(101)	(863)	(62)	(223)	(1,249)
Benefit obligation at 31 December[a e]	30,496	8,364	2,638	10,035	51,533
Movements in fair value of plan assets during the year					

Fair value of plan assets at 1 January	**27,346**	**7,786**	**1**	**3,533**	**38,666**
Exchange adjustments	**822**			**(37)**	**785**
Interest income on plan assets[a]	**1,139**	**240**		**130**	**1,509**
Contributions by plan participants[c]	**37**			**13**	**50**
Contributions by employers (funded plans)	**597**	**386**		**289**	**1,272**
Benefit payments (funded plans)[d]	**(1,087)**	**(1,364)**	**(1)**	**(192)**	**(2,644)**
Disposals	**(9)**			**(13)**	**(22)**
Remeasurements[f]	**2,671**	**730**		**114**	**3,515**
Fair value of plan assets at 31 December	**31,516**	**7,778**		**3,837**	**43,131**
Surplus (deficit) at 31 December	**1,020**	**(586)**	**(2,638)**	**(6,198)**	**(8,402)**
Represented by					
Asset recognized	**1,291**	**6**		**79**	**1,376**
Liability recognized	**(271)**	**(592)**	**(2,638)**	**(6,277)**	**(9,778)**
	1,020	**(586)**	**(2,638)**	**(6,198)**	**(8,402)**
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	**1,285**	**(5)**		**(320)**	**960**
Unfunded	**(265)**	**(581)**	**(2,638)**	**(5,878)**	**(9,362)**
	1,020	**(586)**	**(2,638)**	**(6,198)**	**(8,402)**
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	**(30,231)**	**(7,783)**		**(4,157)**	**(42,171)**
Unfunded	**(265)**	**(581)**	**(2,638)**	**(5,878)**	**(9,362)**
	(30,496)	**(8,364)**	**(2,638)**	**(10,035)**	**(51,533)**

[a] The costs of managing the plan s investments are treated as being part of the return on plan assets, 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] Past service costs include a credit of $73 million as the result of a curtailment in the pension arrangements of a number of employees in the UK and US following divestment transactions. A charge of $29 million for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.

[c] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.

[d] The benefit payments amount shown above comprises $3,269 million benefits plus $59 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for other plans includes $4,874 million for the German plan, which is largely unfunded.

[f] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurment of plan assets as disclosed above.

Table of Contents

30. 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	151	1,007
Past service cost[b]	(1)	20		82	101
Settlement				1	1
Operating charge relating to defined benefit plans	476	348	51	234	1,109
Payments to defined contribution plans	14	223		44	281
Total operating charge	490	571	51	278	1,390
Interest income on plan assets	(1,146)	(304)		(154)	(1,604)
Interest on plan liabilities	1,249	382	134	405	2,170
Other finance expense	103	78	134	251	566
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets[a]	1,523	718		173	2,414
Change in financial assumptions underlying the present value of the plan liabilities	(1,446)	(1,427)	187	(1,093)	(3,779)
Change in demographic assumptions underlying the present value of the plan liabilities			52	(37)	15
Experience gains and losses arising on the plan liabilities	(116)	68	(48)	(126)	(222)
Remeasurements recognized in other comprehensive income	(39)	(641)	191	(1,083)	(1,572)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	25,675	8,617	3,061	8,801	46,154
Exchange adjustments	1,313			254	1,567
Operating charge relating to defined benefit plans	476	348	51	234	1,109
Interest cost	1,249	382	134	405	2,170
Contributions by plan participants[c]	39			14	53
Benefit payments (funded plans)[d]	(1,038)	(593)	(3)	(230)	(1,864)
Benefit payments (unfunded plans)[d]	(7)	(84)	(207)	(394)	(692)
Disposals	(10)			(192)	(202)
Remeasurements	1,562	1,359	(191)	1,256	3,986
Benefit obligation at 31 December[a e]	29,259	10,029	2,845	10,148	52,281
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

Interest income on plan assets[a]	1,146	304		154	1,604
Contributions by plan participants[c]	39			14	53
Contributions by employers (funded plans)	884	153		238	1,275
Benefit payments (funded plans)[d]	(1,038)	(593)	(3)	(230)	(1,864)
Disposals	(10)			(190)	(200)
Remeasurements[f]	1,523	718		173	2,414
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)	(6,615)	(13,615)
Represented by					
Asset recognized				12	12
Liability recognized	(1,913)	(2,243)	(2,844)	(6,627)	(13,627)
	(1,913)	(2,243)	(2,844)	(6,615)	(13,615)
The surplus (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)	(6,076)	(9,746)
	(1,913)	(2,243)	(2,844)	(6,615)	(13,615)
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)	(6,076)	(9,746)
	(29,259)	(10,029)	(2,845)	(10,148)	(52,281)

[a] The costs of managing the plan s investments are treated as being part of the return on plan assets, 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] Past service costs are charges for special termination benefits representing the increased liability arising as a result of early retirements occurring as part of restructuring programmes.

[c] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.

[d] The benefit payments amount shown above comprises $2,501 million benefits plus $55 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for other plans includes $4,783 million for the German plan, which is largely unfunded.

[f] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.

Table of Contents

30. Pensions and other post-retirement benefits continued

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	$ million 2011 Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	383	280	53	135	851
Past service cost	3	184		43	230
Settlement				4	4
Operating charge relating to defined benefit plans	386	464	53	182	1,085
Payments to defined contribution plans	5	199		41	245
Total operating charge	391	663	53	223	1,330
Analysis of the amount credited (charged) to other finance expense					
Interest income on plan assets	(1,361)	(304)		(178)	(1,843)
Interest on plan liabilities	1,263	369	163	448	2,243
Other finance (income) expense	(98)	65	163	270	400
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets[a]	(1,552)	224	(1)	(54)	(1,383)
Change in financial assumptions underlying the present value of the plan liabilities	(2,251)	(468)	(63)	(636)	(3,418)
Change in demographic assumptions underlying the present value of the plan liabilities	(429)	(44)	102	(6)	(377)
Experience gains and losses arising on the plan liabilities	(84)	(102)	89	(26)	(123)
Remeasurements recognized in other comprehensive income	(4,316)	(390)	127	(722)	(5,301)

[a] The costs of managing the plan s investments are treated as being part of the return on plan assets, 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.

At 31 December 2013, reimbursement balances due from or to other companies in respect of pensions amounted to $399 million reimbursement assets (2012 $381 million) and $15 million reimbursement liabilities (2012 $15 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.

Sensitivity analysis

The discount rate, inflation, salary growth, US healthcare cost trend rate and the mortality assumptions all have a significant effect on the amounts reported. A one-percentage point change, in isolation, in certain assumptions as at 31 December 2013 for the group s plans would have had the effects shown in the table below. The effects shown for the expense in 2014 comprise the total of current service cost and net finance income or expense.

$ million

	One percentage point Increase	One percentage point Decrease
Discount rate[a]		
Effect on pension and other post-retirement benefit expense in 2014	**(474)**	**481**
Effect on pension and other post-retirement benefit obligation at 31 December 2013	**(6,918)**	**9,059**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2014	**521**	**(397)**
Effect on pension and other post-retirement benefit obligation at 31 December 2013	**7,120**	**(5,658)**
Salary growth		
Effect on pension and other post-retirement benefit expense in 2014	**142**	**(123)**
Effect on pension and other post-retirement benefit obligation at 31 December 2013	**1,300**	**(1,158)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2014	**16**	**(13)**
Effect on US other post-retirement obligation at 31 December 2013	**278**	**(233)**

[a] The amounts presented reflect that the discount rate is used to determine the asset interest income as well as the interest cost on the obligation.

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 2014 comprises the total of current service cost and net finance income or expense.

$ 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 2014	**52**	**5**	**3**	**9**
Effect on pension and other post-retirement benefit obligation at 31 December 2013	**927**	**95**	**46**	**213**

30. Pensions and other post-retirement benefits continued

Estimated future benefit payments and the weighted average duration of defined benefit obligations

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2023 and the weighted average duration of the defined benefit obligations at the end of the reporting period are as follows:

$ million

Estimated future benefit payments	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
2014	**1,153**	**690**	**174**	**596**	**2,613**
2015	**1,201**	**715**	**177**	**585**	**2,678**
2016	**1,265**	**726**	**178**	**582**	**2,751**
2017	**1,281**	**733**	**178**	**570**	**2,762**
2018	**1,361**	**735**	**178**	**560**	**2,834**
2019-2023	**7,282**	**3,533**	**874**	**2,651**	**14,340**
					years
Weighted average duration	**17.6**	**8.3**	**10.5**	**13.2**	

31. Called-up share capital

The allotted, called up and fully paid share capital at 31 December was as follows:

Issued	**2013** Shares thousand	**2013** $ million	2012 Shares thousand	2012 $ million	2011 Shares thousand	2011 $ 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	**20,959,159**	**5,240**	20,813,410	5,203	20,647,160	5,162
Issue of new shares for the scrip dividend programme	**202,124**	**51**	138,406	35	165,601	41
Issue of new shares for employee share-based payment plans[b]	**18,203**	**5**	7,343	2	649	
Repurchase of ordinary share capital[c]	**(752,854)**	**(188)**				

At 31 December	**20,426,632**	**5,108**	20,959,159	5,240	20,813,410	5,203
		5,129		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 $116 million (2012 $47 million and 2011 $4 million).

[c] Purchased for a total consideration of $5,493 million, including transaction costs of $30 million. All shares purchased were for cancellation. The repurchased shares represented 3.6% of ordinary share capital.

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.

During 2013 the company repurchased 753 million ordinary shares at a cost of $5,463 million as part of the share repurchase programme announced on 22 March 2013. The number of shares in issue is reduced when shares are repurchased, but is not reduced in respect of the year-end commitment to repurchase shares subsequent to the end of the year, for which an amount of $1,430 million has been accrued at 31 December 2013 (2012 nil).

Treasury shares

		2013		2012		2011
	Shares thousand	**Nominal value $ million**	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,823,408**	**455**	1,837,508	459	1,850,699	462
Shares re-issued for employee share-based payment plans	**(35,469)**	**(8)**	(14,100)	(4)	(13,191)	(3)
At 31 December	**1,787,939**	**447**	1,823,408	455	1,837,508	459

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 8.7% (2012 8.8% and 2011 9.0%) of the called-up ordinary share capital of the company.

During 2013, the movement in treasury shares represented less than 0.2% (2012 less than 0.1% and 2011 less than 0.1%) of the ordinary share capital of the company.

Table of Contents

32. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2013	**5,261**	**9,974**	**1,072**	**27,206**	**43,513**
Profit for the year					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)					
Available-for-sale investments (including recycling)					
Cash flow hedges (including recycling)					
Share of items relating to equity-accounted entities, net of tax					
Other					
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset					
Share of items relating to equity-accounted entities, net of tax					
Total comprehensive income					
Dividends	**51**	**(51)**			
Repurchases of ordinary share capital	**(188)**		**188**		
Share-based payments, net of tax[a]	**5**	**138**			**143**
Share of equity-accounted entities changes in equity, net of tax					
Transactions involving non-controlling interests					
At 31 December 2013	**5,129**	**10,061**	**1,260**	**27,206**	**43,656**

	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
Profit for the year					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)					
Available-for-sale investments (including recycling)					
Cash flow hedges (including recycling)					
Share of items relating to equity-accounted entities, net of tax					
Other					
Items that will not be reclassified to profit or loss					

Remeasurements of the net pension and other post-retirement benefit liability or asset					
Share of items relating to equity-accounted entities, net of tax					
Total comprehensive income					
Dividends	35	(35)			
Share-based payments, net of tax[a]	2	57			59
Transactions involving non-controlling 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
Profit for the year					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)					
Available-for-sale investments (including recycling)					
Cash flow hedges (including recycling)					
Share of items relating to equity-accounted entities, net of tax					
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset					
Total comprehensive income					
Dividends	41	(41)			
Share-based payments, net of tax[a]		6			6
Transactions involving non-controlling interests					
At 31 December 2011	5,224	9,952	1,072	27,206	43,454

[a] Includes new share issues and movements in own shares and treasury shares where these relate to employee share-based payment plans.

Table of Contents

$ 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	Non-controlling interests	Total equity
(280)	**(20,774)**	**(21,054)**	**5,128**	**685**	**1,090**	**1,775**	**1,608**	**87,576**	**118,546**	**1,206**	**119,752**
								23,451	**23,451**	**307**	**23,758**
			(1,603)						**(1,603)**	**(15)**	**(1,618)**
				(685)		**(685)**			**(685)**		**(685)**
					(1,785)	**(1,785)**			**(1,785)**		**(1,785)**
								(24)	**(24)**		**(24)**
								(25)	**(25)**		**(25)**
								3,243	**3,243**		**3,243**
								2	**2**		**2**
			(1,603)	**(685)**	**(1,785)**	**(2,470)**		**26,647**	**22,574**	**292**	**22,866**
								(5,441)	**(5,441)**	**(469)**	**(5,910)**
								(6,923)	**(6,923)**		**(6,923)**
(321)	**404**	**83**					**97**	**150**	**473**		**473**
								73	**73**		**73**
										76	**76**
(601)	**(20,370)**	**(20,971)**	**3,525**		**(695)**	**(695)**	**1,705**	**102,082**	**129,302**	**1,105**	**130,407**

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	Non-controlling interests	Total equity
(388)	(20,935)	(21,323)	4,509	389	(122)	267	1,582	83,079	111,568	1,017	112,585
								11,017	11,017	234	11,251
			619		(5)	(5)			614	2	616
				296		296			296		296
					1,217	1,217			1,217		1,217
								(39)	(39)		(39)
								23	23		23
								(1,134)	(1,134)	2	(1,132)
								(6)	(6)		(6)
			619	296	1,212	1,508		9,861	11,988	238	12,226
								(5,294)	(5,294)	(82)	(5,376)
108	161	269					26	(70)	284		284
										33	33
(280)	(20,774)	(21,054)	5,128	685	1,090	1,775	1,608	87,576	118,546	1,206	119,752

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	Non-controlling interests	Total equity
(126)	(21,085)	(21,211)	5,036	463	6	469	1,586	65,754	95,082	904	95,986
								25,212	25,212	397	25,609
			(527)		(1)	(1)			(528)	(10)	(538)
				(74)		(74)			(74)		(74)
					(127)	(127)			(127)		(127)
								(39)	(39)		(39)
								(3,831)	(3,831)	(3)	(3,834)
			(527)	(74)	(128)	(202)		21,342	20,613	384	20,997
								(4,072)	(4,072)	(245)	(4,317)
(262)	150	(112)					(4)	102	(8)		(8)
								(47)	(47)	(26)	(73)
(388)	(20,935)	(21,323)	4,509	389	(122)	267	1,582	83,079	111,568	1,017	112,585

Table of Contents

32. 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 2013, the ESOPs held 32,748,354 shares (2012 22,428,179 shares and 2011 27,784,503 shares) for potential future awards, which had a market value of $253 million (2012 $154 million and 2011 $197 million). At 31 December 2013, a further 12,856,914 ordinary share equivalents (2012 18,673,926 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 except for impairment losses, foreign exchange gains or losses, or changes arising from revised estimates of future cash flows. 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.

Table of Contents

32. 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
			2013
	Pre-tax	**Tax**	**Net of tax**
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	**(1,586)**	**(32)**	**(1,618)**
Available-for-sale investments (including recycling)	**(695)**	**10**	**(685)**
Cash flow hedges (including recycling)	**(1,979)**	**194**	**(1,785)**
Share of items relating to equity-accounted entities, net of tax	**(24)**		**(24)**
Other		**(25)**	**(25)**
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	**4,764**	**(1,521)**	**3,243**
Share of items relating to equity-accounted entities, net of tax	**2**		**2**
Other comprehensive income	**482**	**(1,374)**	**(892)**

			$ million
			2012
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	470	146	616
Available-for-sale investments (including recycling)	305	(9)	296
Cash flow hedges (including recycling)	1,547	(330)	1,217
Share of items relating to equity-accounted entities, net of tax	(39)		(39)
Other		23	23
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	(1,572)	440	(1,132)
Share of items relating to equity-accounted entities, net of tax	(6)		(6)
Other comprehensive income	705	270	975

			$ million
			2011
	Pre-tax	Tax	Net of tax

Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	(524)	(14)	(538)
Available-for-sale investments (including recycling)	(74)		(74)
Cash flow hedges (including recycling)	(164)	37	(127)
Share of items relating to equity-accounted entities, net of tax	(39)		(39)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	(5,301)	1,467	(3,834)
Other comprehensive income	(6,102)	1,490	(4,612)

33. Employee costs and numbers

			$ million
Employee costs	**2013**	2012	2011
Wages and salaries[a b]	**10,161**	9,910	9,333
Social security costs	**958**	908	854
Share-based payments[c]	**719**	674	584
Pension and other post-retirement benefit costs	**1,816**	1,956	1,730
	13,654	13,448	12,501

Number of employees at 31 December[d]	**2013**	2012	2011
Upstream	**24,700**	24,200	22,400
Downstream[e]	**48,000**	51,800	51,500
Other businesses and corporate[f]	**11,100**	10,300	10,100
Gulf Coast Restoration Organization	**100**	100	100
	83,900	86,400	84,100
By geographical area			
US	**19,600**	23,400	22,900
Non-US[e]	**64,300**	63,000	61,200
	83,900	86,400	84,100

Table of Contents

33. Employee costs and numbers continued

Average number of employees[d]	2013 US	2013 Non-US	2013 Total	2012 US	2012 Non-US	2012 Total	2011 US	2011 Non-US	2011 Total
Upstream	**9,400**	**15,100**	**24,500**	9,300	14,100	23,400	8,500	13,400	21,900
Downstream	**9,300**	**39,800**	**49,100**	12,000	39,900	51,900	12,300	39,700	52,000
Other businesses and corporate	**1,900**	**9,000**	**10,900**	1,900	8,700	10,600	1,700	6,500	8,200
Gulf Coast Restoration Organization	**100**		**100**	100		100	100		100
	20,700	**63,900**	**84,600**	23,300	62,700	86,000	22,600	59,600	82,200

[a] Includes termination payments of $212 million (2012 $77 million and 2011 $126 million).
[b] Wages and salaries for 2012 and 2011 have been amended.
[c] The group provides certain employees with shares and share options as part of their remuneration packages. The majority of these share-based payment arrangements are equity-settled.
[d] Reported to the nearest 100.
[e] Includes 14,100 (2012 14,700 and 2011 14,600) service station staff.
[f] Includes 4,300 (2012 3,600 and 2011 4,000) agricultural, operational and seasonal workers in Brazil.

34. Remuneration of directors and senior management

Remuneration of directors

$ million	**2013**	2012	2011
Total for all directors			
Emoluments	**16**	12	10
Gains made on exercise of share options			
Amounts awarded under incentive schemes	**2**	3	1
Total	**18**	15	11

Emoluments

These amounts comprise fees and benefits 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 2013 (2012 nil and 2011 nil).

Pension contributions

During 2013 two executive directors participated in a non-contributory pension scheme established for UK employees. Two US executive directors participated in the US BP Retirement Accumulation Plan during 2013.

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 page 81.

Remuneration of directors and senior management

			$ million
Total for all senior management	**2013**	2012[a]	2011[a]
Total for all senior management			
Short-term employee benefits	**36**	29	34
Pensions and other post-retirement benefits	**3**	3	3
Share-based payments	**43**	37	28
Total	**82**	69	65

[a] Prior year comparatives have been amended to include the portion of bonuses that were deferred and will be settled in shares in the future.

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 and benefits paid to the non-executive chairman and non-executive directors, these amounts comprise, for executive directors and senior managers, salary and benefits earned during the year, plus cash bonuses awarded for the year. Deferred annual bonus awards, to be settled in shares, are included in share-based payments. Short-term employee benefits includes compensation for loss of office of $3 million (2012 nil and 2011 $9 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, ACBD, SVP and RSP.

Table of Contents

35. Contingent liabilities

Contingent liabilities related to the Gulf of Mexico oil spill

Details of contingent liabilities related to the Gulf of Mexico oil spill are set out in Note 2.

Contingent liabilities not related to the Gulf of Mexico oil spill

There were contingent liabilities at 31 December 2013 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 19.

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, commodities trading, premises-liability claims, consumer protection, 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 tax returns in many jurisdictions throughout the world. Various tax authorities are currently examining the group s 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 that are not provided for 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 possible 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. If oil and natural gas production facilities and pipelines are sold to third parties and the subsequent owner is unable to meet their decommissioning obligations, judgement must be used to determine whether BP is then responsible for decommissioning, and if so the extent of that responsibility.

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.

36. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2013 amounted to $13,705 million (2012 $14,894 million). BP s share of capital commitments of joint ventures amounted to $317 million (2012 $293 million).

Table of Contents

37. Auditor s remuneration

			$ million
Fees EY	**2013**	2012	2011
The audit of the company annual accounts[a]	**26**	26	26
The audit of accounts of any subsidiaries of the company	**13**	13	15
Total audit	**39**	39	41
Audit-related assurance services[b]	**8**	7	6
Total audit and audit-related assurance services	**47**	46	47
Taxation compliance services	**1**	2	1
Taxation advisory services	**1**	2	1
Services relating to corporate finance transactions	**2**	2	4
Other assurance services	**1**	1	1
Total non-audit or non-audit-related assurance services	**5**	7	7
Services relating to BP pension plans[c]	**1**	1	1
	53	54	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 $240,000 (2012 $50,000 and 2011 $108,000).
2013 includes $3 million of additional fees for 2012, and 2012 includes $2 million of additional fees for 2011.
Auditors remuneration is included in the income statement within distribution and administration expenses.

The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young compared with that of other potential service providers. These services are for a fixed term.

Under SEC regulations, the remuneration of the auditor of $53 million (2012 $54 million and 2011 $55 million) is required to be presented as follows: audit $39 million (2012 $39 million and 2011 $41 million); other audit-related services $8 million (2012 $7 million and 2011 $6 million); tax $2 million (2012 $4 million and 2011 $2 million); and all other fees $4 million (2012 $4 million and 2011 $6 million).

Table of Contents

38. Subsidiaries, joint arrangements and associates

The more important subsidiaries, joint arrangements and associates of the group at 31 December 2013 and the group percentage of ordinary share capital or joint arrangement 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. The group has interests in a number of joint arrangements, but none of these is individually material to the group. A complete list of investments in subsidiaries, joint arrangements 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 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
*Burmah Castrol	100	Scotland	Lubricants
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
Angola			
BP Exploration (Angola)	100	England & Wales	Exploration and production
Australia			
BP Australia Capital Markets	100	Australia	Finance
BP Finance Australia	100	Australia	Finance
Azerbaijan			
BP Exploration (Caspian Sea)	100	England & Wales	Exploration and production
Brazil			
BP Energy do Brazil	100	Brazil	Exploration and production
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Norway			
BP Norge	100	Norway	Exploration and production
UK			
BP Capital Markets	100	England & Wales	Finance
US			
*BP Holdings North America	100	England & Wales	Investment holding
Atlantic Richfield Company	100	US	
BP America	100	US	
	100	US	

BP America Production Company			Exploration and production, refining and marketing
BP Company North America	100	US	pipelines and petrochemicals
BP Corporation North America	100	US	
BP Exploration & Production	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
Standard Oil Company	100	US	
BP Capital Markets America	100	US	Finance

Associates	%	Country of incorporation	Principal activities
Russia			
Rosneft	20	Russia	Integrated oil operations

Table of Contents

39. 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.

Income statement

$ million

For the year ended 31 December					**2013**
	Issuer BP Exploration (Alaska) Inc.	**Guarantor BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Sales and other operating revenues	**5,397**		**379,136**	**(5,397)**	**379,136**
Earnings from joint ventures after interest and tax			**447**		**447**
Earnings from associates after interest and tax			**2,742**		**2,742**
Equity-accounted income of subsidiaries after interest and tax		**24,693**		**(24,693)**	
Interest and other income	**7**	**118**	**841**	**(189)**	**777**
Gains on sale of businesses and fixed assets			**13,115**		**13,115**
Total revenues and other income	**5,404**	**24,811**	**396,281**	**(30,279)**	**396,217**
Purchases	**861**		**302,887**	**(5,397)**	**298,351**
Production and manufacturing expenses	**1,473**		**26,054**		**27,527**
Production and similar taxes	**1,010**		**6,037**		**7,047**
Depreciation, depletion and amortization	**616**		**12,894**		**13,510**
Impairment and losses on sale of businesses and fixed assets	**(68)**		**2,029**		**1,961**
Exploration expense			**3,441**		**3,441**
Distribution and administration expenses	**108**	**1,234**	**11,728**		**13,070**
Fair value gain on embedded derivatives			**(459)**		**(459)**
Profit before interest and taxation	**1,404**	**23,577**	**31,670**	**(24,882)**	**31,769**

Finance costs	**42**	**43**	**1,172**	**(189)**	**1,068**
Net finance (income) expense relating to pensions and other post-retirement benefits		**81**	**399**		**480**
Profit before taxation	**1,362**	**23,453**	**30,099**	**(24,693)**	**30,221**
Taxation	**522**	**2**	**5,939**		**6,463**
Profit for the year	**840**	**23,451**	**24,160**	**(24,693)**	**23,758**
Attributable to					
BP shareholders	**840**	**23,451**	**23,853**	**(24,693)**	**23,451**
Non-controlling interests			**307**		**307**
	840	**23,451**	**24,160**	**(24,693)**	**23,758**

Statement of comprehensive income

					$ million
For the year ended 31 December					**2013**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Profit for the year	**840**	**23,451**	**24,160**	**(24,693)**	**23,758**
Other comprehensive income		**2,819**	**(3,711)**		**(892)**
Total comprehensive income	**840**	**26,270**	**20,449**	**(24,693)**	**22,866**
Attributable to					
BP shareholders	**840**	**26,270**	**20,157**	**(24,693)**	**22,574**
Non-controlling interests			**292**		**292**
	840	**26,270**	**20,449**	**(24,693)**	**22,866**

Table of Contents

39. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

					$ million
For the year ended 31 December					2012
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	5,501		375,765	(5,501)	375,765
Earnings from joint ventures after interest and tax			260		260
Earnings from associates after interest and tax			3,675		3,675
Equity-accounted income of subsidiaries after interest and tax	(59)	12,649		(12,590)	
Interest and other income	12	187	1,764	(286)	1,677
Gains on sale of businesses and fixed assets	3,580		6,697	(3,580)	6,697
Total revenues and other income	9,034	12,836	388,161	(21,957)	388,074
Purchases	777		297,498	(5,501)	292,774
Production and manufacturing expenses	1,475		32,451		33,926
Production and similar taxes	1,374		6,784		8,158
Depreciation, depletion and amortization	457		12,230		12,687
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	11,070	21,111	(16,371)	19,769
Finance costs	48	43	1,182	(201)	1,072
Net finance expense relating to pensions and other post-retirement benefits		103	463		566
Profit before taxation	3,911	10,924	19,466	(16,170)	18,131
Taxation	203	(93)	6,770		6,880
Profit for the year	3,708	11,017	12,696	(16,170)	11,251
Attributable to					
BP shareholders	3,708	11,017	12,462	(16,170)	11,017
Non-controlling interests			234		234
	3,708	11,017	12,696	(16,170)	11,251

Statement of comprehensive income continued

					$ million
For the year ended 31 December					2012
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit for the year	3,708	11,017	12,696	(16,170)	11,251
Other comprehensive income		(232)	1,207		975
Total comprehensive income	3,708	10,785	13,903	(16,170)	12,226
Attributable to					
BP shareholders	3,708	10,785	13,665	(16,170)	11,988
Non-controlling interests			238		238
	3,708	10,785	13,903	(16,170)	12,226

Table of Contents

39. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

$ 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
Sales and other operating revenues	6,159		375,713	(6,159)	375,713
Earnings from joint ventures after interest and tax			767		767
Earnings from associates after interest and tax			4,916		4,916
Equity-accounted income of subsidiaries after interest and tax	313	26,019		(26,332)	
Interest and other income	10	242	756	(320)	688
Gains on sale of businesses and fixed assets		1	4,131		4,132
Total revenues and other income	6,482	26,262	386,283	(32,811)	386,216
Purchases	978		290,314	(6,159)	285,133
Production and manufacturing expenses	1,280		22,883		24,163
Production and similar taxes	1,684		6,596		8,280
Depreciation, depletion and amortization	335		11,022		11,357
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	25,214	38,970	(26,543)	39,815
Finance costs	32	47	1,319	(211)	1,187
Net finance (income) expense relating to pensions and other post-retirement benefits		(94)	494		400
Profit before taxation	2,142	25,261	37,157	(26,332)	38,228
Taxation	729	49	11,841		12,619
Profit for the year	1,413	25,212	25,316	(26,332)	25,609
Attributable to					
BP shareholders	1,413	25,212	24,919	(26,332)	25,212
Non-controlling interests			397		397
	1,413	25,212	25,316	(26,332)	25,609

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	25,212	25,316	(26,332)	25,609
Other comprehensive income		(3,674)	(938)		(4,612)
Total comprehensive income	1,413	21,538	24,378	(26,332)	20,997
Attributable to					
BP shareholders	1,413	21,538	23,994	(26,332)	20,613
Non-controlling interests			384		384
	1,413	21,538	24,378	(26,332)	20,997

Table of Contents

39. Condensed consolidating information on certain US subsidiaries continued

Balance sheet

					$ million
At 31 December					**2013**
	Issuer BP Exploration (Alaska) Inc.	**Guarantor BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Non-current assets					
Property, plant and equipment	**8,546**		**125,144**		**133,690**
Goodwill			**12,181**		**12,181**
Intangible assets	**417**		**21,622**		**22,039**
Investments in joint ventures			**9,199**		**9,199**
Investments in associates		**2**	**16,634**		**16,636**
Other investments			**1,565**		**1,565**
Subsidiaries equity-accounted basis		**142,143**		**(142,143)**	
Fixed assets	**8,963**	**142,145**	**186,345**	**(142,143)**	**195,310**
Loans			**5,356**	**(4,593)**	**763**
Trade and other receivables			**5,985**		**5,985**
Derivative financial instruments			**3,509**		**3,509**
Prepayments	**22**		**900**		**922**
Deferred tax assets			**985**		**985**
Defined benefit pension plan surpluses		**1,020**	**356**		**1,376**
	8,985	**143,165**	**203,436**	**(146,736)**	**208,850**
Current assets					
Loans			**216**		**216**
Inventories	**152**		**29,079**		**29,231**
Trade and other receivables	**9,593**	**21,550**	**42,363**	**(33,675)**	**39,831**
Derivative financial instruments			**2,675**		**2,675**
Prepayments	**18**		**1,370**		**1,388**
Current tax receivable			**512**		**512**
Other investments			**467**		**467**
Cash and cash equivalents		**6**	**22,514**		**22,520**
	9,763	**21,556**	**99,196**	**(33,675)**	**96,840**
Assets classified as held for sale					
	9,763	**21,556**	**99,196**	**(33,675)**	**96,840**
Total assets	**18,748**	**164,721**	**302,632**	**(180,411)**	**305,690**
Current liabilities					
Trade and other payables	**889**	**2,727**	**77,218**	**(33,675)**	**47,159**
Derivative financial instruments			**2,322**		**2,322**
Accruals	**171**	**1,540**	**7,249**		**8,960**
Finance debt			**7,381**		**7,381**

Current tax payable	**166**		**1,779**		**1,945**
Provisions	**1**		**5,044**		**5,045**
	1,227	**4,267**	**100,993**	**(33,675)**	**72,812**
Liabilities directly associated with assets classified as held for sale					
	1,227	**4,267**	**100,993**	**(33,675)**	**72,812**
Non-current liabilities					
Other payables	**9**	**4,584**	**4,756**	**(4,593)**	**4,756**
Derivative financial instruments			**2,225**		**2,225**
Accruals		**58**	**489**		**547**
Finance debt			**40,811**		**40,811**
Deferred tax liabilities	**1,659**		**15,780**		**17,439**
Provisions	**1,942**		**24,973**		**26,915**
Defined benefit pension plan and other post-retirement benefit plan deficits			**9,778**		**9,778**
	3,610	**4,642**	**98,812**	**(4,593)**	**102,471**
Total liabilities	**4,837**	**8,909**	**199,805**	**(38,268)**	**175,283**
Net assets	**13,911**	**155,812**	**102,827**	**(142,143)**	**130,407**
Equity					
BP shareholders equity	**13,911**	**155,812**	**101,722**	**(142,143)**	**129,302**
Non-controlling interests			**1,105**		**1,105**
	13,911	**155,812**	**102,827**	**(142,143)**	**130,407**

Table of Contents

39. Condensed consolidating information on certain US subsidiaries continued

Balance sheet continued

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2012 BP group
Non-current assets					
Property, plant and equipment	8,343		116,988		125,331
Goodwill			12,190		12,190
Intangible assets	379		24,253		24,632
Investments in joint ventures			8,614		8,614
Investments in associates		2	2,996		2,998
Other investments			2,704		2,704
Subsidiaries equity-accounted basis		136,553		(136,553)	
Fixed assets	8,722	136,555	167,745	(136,553)	176,469
Loans			4,924	(4,282)	642
Trade and other receivables			5,961		5,961
Derivative financial instruments			4,294		4,294
Prepayments	34		796		830
Deferred tax assets			874		874
Defined benefit pension plan surpluses			12		12
	8,756	136,555	184,606	(140,835)	189,082
Current assets					
Loans			247		247
Inventories	174		28,029		28,203
Trade and other receivables	11,835	17,496	43,008	(34,728)	37,611
Derivative financial instruments			4,507		4,507
Prepayments	15		1,076		1,091
Current tax receivable			456		456
Other investments			319		319
Cash and cash equivalents		9	19,626		19,635
	12,024	17,505	97,268	(34,728)	92,069
Assets classified as held for sale			19,315		19,315
	12,024	17,505	116,583	(34,728)	111,384
Total assets	20,780	154,060	301,189	(175,563)	300,466
Current liabilities					
Trade and other payables	3,914	2,577	74,910	(34,728)	46,673
Derivative financial instruments			2,658		2,658
Accruals	140	27	6,708		6,875
Finance debt			10,033		10,033

Current tax payable	145		2,358		2,503
Provisions	1		7,586		7,587
	4,200	2,604	104,253	(34,728)	76,329
Liabilities directly associated with assets classified as held for sale			846		846
	4,200	2,604	105,099	(34,728)	77,175
Non-current liabilities					
Other payables	8	4,449	2,117	(4,282)	2,292
Derivative financial instruments			2,723		2,723
Accruals		38	453		491
Finance debt			38,767		38,767
Deferred tax liabilities	1,654		13,589		15,243
Provisions	1,887		28,509		30,396
Defined benefit pension plan and other post-retirement benefit plan deficits		1,913	11,714		13,627
	3,549	6,400	97,872	(4,282)	103,539
Total liabilities	7,749	9,004	202,971	(39,010)	180,714
Net assets	13,031	145,056	98,218	(136,553)	119,752
Equity					
BP shareholders equity	13,031	145,056	97,012	(136,553)	118,546
Non-controlling interests			1,206		1,206
	13,031	145,056	98,218	(136,553)	119,752

Table of Contents

39. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

					$ million
For the year ended 31 December					**2013**
	Issuer BP Exploration (Alaska) Inc.	**Guarantor BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Net cash provided by operating activities	**746**	**11,488**	**25,094**	**(16,228)**	**21,100**
Net cash used in investing activities	**(746)**	**(690)**	**(6,419)**		**(7,855)**
Net cash used in financing activities		**(10,801)**	**(15,827)**	**16,228**	**(10,400)**
Currency translation differences relating to cash and cash equivalents			**40**		**40**
Increase (decrease) in cash and cash equivalents		**(3)**	**2,888**		**2,885**
Cash and cash equivalents at beginning of year		**9**	**19,626**		**19,635**
Cash and cash equivalents at end of year		**6**	**22,514**		**22,520**

					$ million
For the year ended 31 December					2012
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities	681	12,381	20,932	(13,515)	20,479
Net cash used in investing activities	(680)	(7,060)	(5,335)		(13,075)
Net cash used in financing activities		(5,312)	(10,213)	13,515	(2,010)
Currency translation differences relating to cash and cash equivalents			64		64
Increase in cash and cash equivalents	1	9	5,448		5,458
Cash and cash equivalents at beginning of year	(1)		14,178		14,177
Cash and cash equivalents at end of year		9	19,626		19,635

					$ million
For the year ended 31 December					2011
	Issuer BP Exploration	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group

	(Alaska) Inc.				
Net cash provided by operating activities	661	8,321	25,178	(11,942)	22,218
Net cash used in investing activities	(661)	(3,710)	(22,382)		(26,753)
Net cash (used in) provided by financing activities		(4,615)	(6,850)	11,942	477
Currency translation differences relating to cash and cash equivalents			(493)		(493)
Decrease in cash and cash equivalents		(4)	(4,547)		(4,551)
Cash and cash equivalents at beginning of year	(1)	4	18,725		18,728
Cash and cash equivalents at end of year	(1)		14,178		14,177

Table of Contents

Supplementary information on oil and natural gas (unaudited)

2013 reserves and production information for equity-accounted entities includes BP s share of TNK-BP from 1 January to 20 March, and Rosneft for the period 21 March to 31 December. For the period 22 October 2012 to 31 December 2012, and throughout all of 2013, financial information for equity-accounted entities does not include any information for TNK-BP, as equity accounting ceased on 22 October 2012. Comparative information for 2012 and 2011 has been restated to reflect the adoption of IFRS 11 Joint Arrangements . For further information see Financial statements Note 1.

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 to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For details on BP s proved reserves and production compliance and governance processes, see page 245.

Table of Contents

Oil and natural gas exploration and production activities

	Europe		North America		South America	Africa	Asia		Austra
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia	
Subsidiaries[a]									
Capitalized costs at 31 December[b]									
Gross capitalized costs									
Proved properties	**29,314**	**10,040**	**75,313**	**2,501**	**8,809**	**35,720**		**20,726**	**4,6**
Unproved properties	**316**	**195**	**6,816**	**2,408**	**3,366**	**5,079**		**2,756**	**8**
	29,630	**10,235**	**82,129**	**4,909**	**12,175**	**40,799**		**23,482**	**5,4**
Accumulated depreciation	**18,707**	**3,650**	**38,236**	**193**	**5,063**	**20,082**		**10,069**	**1,9**
Net capitalized costs	**10,923**	**6,585**	**43,893**	**4,716**	**7,112**	**20,717**		**13,413**	**3,5**
Costs incurred for the year ended 31 December[b]									
Acquisition of properties									
Proved			**1**		**7**				
Unproved			**158**		**284**	**30**		**7**	
			159		**291**	**30**		**7**	
Exploration and appraisal costs[c]	**178**	**14**	**1,291**	**194**	**951**	**883**		**1,090**	**2**
Development	**1,942**	**455**	**4,877**	**569**	**683**	**2,755**		**2,082**	**1**
Total costs	**2,120**	**469**	**6,327**	**763**	**1,925**	**3,668**		**3,179**	**3**
Results of operations for the year ended 31 December									
Sales and other operating revenues[d]									
Third parties	**1,129**	**183**	**934**	**5**	**2,413**	**3,195**		**1,005**	**1,7**
Sales between businesses	**1,661**	**1,280**	**14,047**	**12**	**1,154**	**6,518**		**11,432**	**9**
	2,790	**1,463**	**14,981**	**17**	**3,567**	**9,713**		**12,437**	**2,7**
Exploration expenditure	**280**	**17**	**437**	**28**	**1,477**	**387**		**768**	
Production costs	**1,102**	**430**	**3,691**	**42**	**892**	**1,623**		**1,091**	**1**
Production taxes	**(35)**		**1,112**		**184**			**5,660**	**1**
Other costs (income)[e]	**(1,731)**	**86**	**3,241**	**55**	**322**	**89**	**65**	**84**	**3**
Depreciation, depletion and amortization	**504**	**490**	**3,268**		**559**	**3,132**		**2,174**	**2**
Impairments and (gains) losses on sale of businesses and fixed assets	**118**	**15**	**(80)**		**129**	**29**		**(16)**	**2**
	238	**1,038**	**11,669**	**125**	**3,563**	**5,260**	**65**	**9,761**	**1,1**
Profit (loss) before taxation[f]	**2,552**	**425**	**3,312**	**(108)**	**4**	**4,453**	**(65)**	**2,676**	**1,5**

Allocable taxes	**554**	**475**	**1,204**	**(26)**	**642**	**1,925**	**(2)**	**682**	**6**
Results of operations	**1,998**	**(50)**	**2,108**	**(82)**	**(638)**	**2,528**	**(63)**	**1,994**	**9**

Upstream, Rosneft and TNK-BP segments replacement cost profit before interest and tax

Exploration and production activities subsidiaries (as above)	**2,552**	**425**	**3,312**	**(108)**	**4**	**4,453**	**(65)**	**2,676**	**1,5**
Midstream activities subsidiaries[g]	**244**	**(40)**	**296**	**(14)**	**153**	**(154)**	**(4)**	**(29)**	**3**
TNK-BP gain on sale							**12,500**		
Equity-accounted entities[h]		**28**	**17**		**405**	**24**	**2,158**	**553**	
Total replacement cost profit before interest and tax	**2,796**	**413**	**3,625**	**(122)**	**562**	**4,323**	**14,589**	**3,200**	**1,9**

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes our share of oil and natural gas exploration and production activities of joint operations. 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, Australia and Angola.

[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[c] 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.

[d] Presented net of transportation costs, purchases and sales taxes.

[e] Includes property taxes, other government take and the fair value gain on embedded derivatives of $459 million. The UK region includes a $1,055 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

[f] Excludes the unwinding of the discount on provisions and payables amounting to $141 million which is included in finance costs in the group income statement.

[g] Midstream and other activities excludes inventory holding gains and losses.

[h] The profits of equity-accounted entities are included after interest and tax.

Table of Contents

Oil and natural gas exploration and production activities continued

$ million

2013

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)[b]										
Capitalized costs at 31 December[c]										
Gross capitalized costs										
Proved properties					**7,648**		**18,942**	**4,239**		**30,829**
Unproved properties					**29**		**638**	**21**		**688**
					7,677		**19,580**	**4,260**		**31,517**
Accumulated depreciation					**3,282**		**1,077**	**4,061**		**8,420**
Net capitalized costs					**4,395**		**18,503**	**199**		**23,097**
Costs incurred for the year ended 31 December[d]										
Acquisition of properties										
Proved							**1,816**			**1,816**
Unproved							**657**			**657**
							2,473			**2,473**
Exploration and appraisal costs[e]					**8**		**133**	**12**		**153**
Development					**714**		**1,860**	**538**		**3,112**
Total costs					**722**		**4,466**	**550**		**5,738**
Results of operations for the year ended 31 December										
Sales and other operating revenues[f]										
Third parties					**2,294**		**435**	**4,770**		**7,499**
Sales between businesses							**9,679**	**14**		**9,693**
					2,294		**10,114**	**4,784**		**17,192**

Exploration expenditure					126	1	127
Production costs			586		1,177	404	2,167
Production taxes			630		4,511	3,645	8,786
Other costs (income)			6		94	(1)	99
Depreciation, depletion and amortization			317		1,232	544	2,093
Impairments and losses on sale of businesses and fixed assets					37		37
			1,539		7,177	4,593	13,309
Profit (loss) before taxation			755		2,937	191	3,883
Allocable taxes			460		367	40	867
Results of operations			295		2,570	151	3,016
Exploration and production activities equity-accounted entities after tax (as above)			295		2,570	151	3,016
Midstream and other activities after tax[g]	28	17	110	24	(412)	402	169
Total replacement cost profit after interest and tax	28	17	405	24	2,158	553	3,185

[a] Amounts reported for Russia in this table include BP s share of Rosneft s worldwide activities, including insignificant amounts outside Russia.

[b] 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 and Rosneft are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.

[c] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[d] The amounts shown reflect BP s share of equity-accounted entities costs incurred, and not the costs incurred by BP in acquiring an interest in equity-accounted entities.

[e] 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.

[f] Presented net of transportation costs and sales taxes.

[g] Includes interest, non-controlling interest and the net results of equity-accounted entities, and excludes inventory holding gains and losses.

Table of Contents

Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2012 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	28,370	9,421	70,133	1,928	8,153	32,755		16,757	3,676	171,193
Unproved properties	400	199	7,084	2,244	3,590	4,524		4,920	1,540	24,501
	28,770	9,620	77,217	4,172	11,743	37,279		21,677	5,216	195,694
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	3,975	7,299	20,378		13,317	3,699	106,653
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	230	758	1,024		814	241	4,356
Development	1,907	784	3,866	611	581	2,992		1,591	221	12,553
Total costs	2,080	831	6,302	841	1,417	4,255		2,337	462	18,525
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	63	109	221	(330)	84	264	2,520
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	246	1,815	4,159	(330)	9,691	934	27,797
Profit (loss) before taxation[g]	3,062	176	7,075	(226)	1,195	4,898	330	2,953	1,730	21,193
Allocable taxes	1,121	(313)	2,762	(67)	804	2,371	(13)	663	755	8,083
Results of operations	1,941	489	4,313	(159)	391	2,527	343	2,290	975	13,110

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	(226)	1,195	4,898	330	2,953	1,730	21,193
Midstream activities subsidiaries[h]	(250)	(114)	(173)	774	163	(46)	11	32	370	767
Equity-accounted entities[i]		35	16		160	48	3,005	640		3,904
Total replacement cost profit before interest and tax	2,812	97	6,918	548	1,518	4,900	3,346	3,625	2,100	25,864

[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 or 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 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 a net non-operating gain of $351 million including 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 $173 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.

Table of Contents

Oil and natural gas exploration and production activities continued

										$ million
										2012
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)[b]										
Capitalized costs at 31 December[c]										
Gross capitalized costs										
Proved properties					6,958			4,036		10,994
Unproved properties					21			16		37
					6,979			4,052		11,031
Accumulated depreciation					2,965			3,648		6,613
Net capitalized costs					4,014			404		4,418
Costs incurred for the year ended 31 December[c]										
Acquisition of properties[d]										
Proved							4			4
Unproved					439		15			454
					439		19			458
Exploration and appraisal costs[e]					31		195	7		233
Development					599		1,560	556		2,715
Total costs					1,069		1,774	563		3,406
Results of operations for the year ended 31 December										
Sales and other operating revenues[f]										
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)					(11)		(24)	(2)		(37)
					328		786	538		1,652

Depreciation, depletion and amortization							
Impairments and losses on sale of businesses and fixed assets					(27)		(27)
			1,862		6,833	4,077	12,772
Profit (loss) before taxation			405		3,278	189	3,872
Allocable taxes			294		536	54	884
Results of operations			111		2,742	135	2,988
Exploration and production activities equity-accounted entities after tax (as above)			111		2,742	135	2,988
Midstream and other activities after tax[g]	35	16	49	48	263	505	916
Total replacement cost profit after interest and tax	35	16	160	48	3,005	640	3,904

[a] The Russia region includes BP s equity-accounted share of TNK-BP s earnings. For 2012, equity-accounted earnings are included until 21 October 2012 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.

[b] 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.

[c] 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.

[d] Includes costs capitalized as a result of asset exchanges.

[e] 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.

[f] Presented net of transportation costs and sales taxes.

[g] Includes interest, non-controlling interest and the net results of equity-accounted entities, and excludes inventory holding gains and losses.

Table of Contents

Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2011 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	1,296	7,471	29,358		14,833	3,370	176,439
Unproved properties	368	180	6,198	2,017	2,986	3,689		4,495	1,279	21,212
	37,859	9,174	79,824	3,313	10,457	33,047		19,328	4,649	197,651
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	3,174	6,618	18,452		13,093	3,355	104,872
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	132	271	490	6	511	225	2,413
Development	1,361	889	3,016	227	405	2,933		1,340	251	10,422
Total costs	1,572	891	5,178	367	3,505	4,102	6	6,592	476	22,689
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	62	935	215	72	118	257	5,091
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	158	1,189	3,210	81	8,150	840	28,616
Profit (loss) before taxation[g]	4,468	806	6,343	(113)	2,483	5,001	(81)	4,111	1,738	24,756
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	46	1,278	2,817	(60)	3,110	1,061	14,850

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	(113)	2,483	5,001	(81)	4,111	1,738	24,756
Midstream activities subsidiaries[h]	(118)	29	(157)	299	78	(4)	(1)	42	284	452
Equity-accounted entities[i]		12	10		525	69	4,095	573		5,284
Total replacement cost profit before interest and tax	4,350	847	6,196	186	3,086	5,066	4,013	4,726	2,022	30,492

[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 $267 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.

Table of Contents

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		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties					6,562		16,214	3,571		26,347
Unproved properties					19		652	9		680
					6,581		16,866	3,580		27,027
Accumulated depreciation					2,644		6,978	3,017		12,639
Net capitalized costs					3,937		9,888	563		14,388
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]					2		167	9		178
Development					587		1,862	435		2,884
Total costs					595		2,066	490		3,151
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	95	69	280	509	975
Total replacement cost profit after interest and tax	12	10	525	69	4,095	573	5,284

[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, non-controlling interest and the net results of equity-accounted entities, and excludes inventory holding gains and losses

Table of Contents

Movements in estimated net proved reserves

million barrels

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US[b]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2013										
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
Changes attributable to										
Revisions of previous estimates	(78)	(19)	(141)		30	26		65	(12)	(129)
Improved recovery	12		52		1	2		65		132
Purchases of reserves-in-place										
Discoveries and extensions			4					39	3	46
Production[c]	(22)	(12)	(132)		(11)	(80)		(52)	(9)	(318)
Sales of reserves-in-place	(36)		(11)							(47)
	(124)	(31)	(228)		20	(52)		117	(18)	(316)
At 31 December 2013[d]										
Developed	169	163	1,297		29	320		320	57	2,355
Undeveloped	380	55	907		45	195		202	22	1,806
	549	218	2,204		74	515		522	79	4,161
Equity-accounted entities (BP share)[e]										
At 1 January 2013										
Developed					339	12	2,492	198		3,041
Undeveloped					351	11	1,962	13		2,337
					690	23	4,454	211		5,378
Changes attributable to										
Revisions of previous estimates				1	(21)	(3)	384	1		362
Improved recovery					27					27
Purchases of reserves-in-place					34		4,579			4,613
Discoveries and extensions					12		228			240

Production					**(27)**		**(303)**	**(85)**		**(415)**
Sales of reserves-in-place					**(85)**		**(4,399)**			**(4,484)**
				1	**(60)**	**(3)**	**489**	**(84)**		**343**
At 31 December 2013[f g]										
Developed					**316**	**10**	**3,064**	**120**		**3,510**
Undeveloped				**1**	**314**	**10**	**1,879**	**7**		**2,211**
				1	**630**	**20**	**4,943**	**127**		**5,721**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2013										
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**
At 31 December 2013										
Developed	**169**	**163**	**1,297**		**345**	**330**	**3,064**	**440**	**57**	**5,865**
Undeveloped	**380**	**55**	**907**	**1**	**359**	**205**	**1,879**	**209**	**22**	**4,017**
	549	**218**	**2,204**	**1**	**704**	**535**	**4,943**	**649**	**79**	**9,882**

[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 72 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 5,500 barrels per day.

[d] Includes 551 million barrels of NGLs. Also includes 21 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[f] Includes 131 million barrels of NGLs. Also includes 23 million barrels of crude oil in respect of the 0.47% non-controlling interest in Rosneft.

[g] Total proved liquid reserves held as part of our equity interest in Rosneft is 4,975 million barrels, comprising less than 1 mmboe in Vietnam and Canada, 32 million barrels in Venezuela and 4,943 million barrels in Russia.

Table of Contents

Movements in estimated net proved reserves continued

billion cubic

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	2 To
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2013										
Developed	1,038	340	8,245	4	3,588	1,139		926	3,282	18,
Undeveloped	666	141	2,986		6,250	1,923		413	2,323	14,
	1,704	481	11,231	4	9,838	3,062		1,339	5,605	33,
Changes attributable to										
Revisions of previous estimates	(62)	(47)	(1,166)	10	62	(138)		2,148	(140)	
Improved recovery	49		630		144	28		94		
Purchases of reserves-in-place	9									
Discoveries and extensions			39			55		1,875	511	2,
Production[b]	(66)	(31)	(635)	(4)	(819)	(239)		(199)	(289)	(2,
Sales of reserves-in-place	(677)		(152)					(67)		(
	(747)	(78)	(1,284)	6	(613)	(294)		3,851	82	
At 31 December 2013[c]										
Developed	643	364	7,122	10	3,109	961		1,519	3,932	17,
Undeveloped	314	39	2,825		6,116	1,807		3,671	1,755	16,
	957	403	9,947	10	9,225	2,768		5,190	5,687	34,
Equity-accounted entities (BP share)[d]										
At 1 January 2013										
Developed					1,276	175	2,617	128		4,
Undeveloped					904	164	1,759	18		2,
					2,180	339	4,376	146		7,
Changes attributable to										
Revisions of previous estimates				1	3	29	685	1		
Improved recovery					64			3		
Purchases of reserves-in-place					14		8,871	33		8,
Discoveries and extensions					51		254			
Production[b]					(163)	(3)	(292)	(23)		(
Sales of reserves-in-place					(38)		(4,669)	(74)		(4,
				1	(69)	26	4,849	(60)		4,
At 31 December 2013[e f]										
Developed					1,364	230	4,171	72		5,
Undeveloped				1	747	135	5,054	14		5,

				1	**2,111**	**365**	**9,225**	**86**		**11,**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2013										
Developed	**1,038**	**340**	**8,245**	**4**	**4,864**	**1,314**	**2,617**	**1,054**	**3,282**	**22,**
Undeveloped	**666**	**141**	**2,986**		**7,154**	**2,087**	**1,759**	**431**	**2,323**	**17,**
	1,704	**481**	**11,231**	**4**	**12,018**	**3,401**	**4,376**	**1,485**	**5,605**	**40,**
At 31 December 2013										
Developed	**643**	**364**	**7,122**	**10**	**4,473**	**1,191**	**4,171**	**1,591**	**3,932**	**23,**
Undeveloped	**314**	**39**	**2,825**	**1**	**6,863**	**1,942**	**5,054**	**3,685**	**1,755**	**22,**
	957	**403**	**9,947**	**11**	**11,336**	**3,133**	**9,225**	**5,276**	**5,687**	**45,**

[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 180 billion cubic feet of natural gas consumed in operations, 149 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities.

[c] Includes 2,685 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[d] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[e] Includes 41 billion cubic feet of natural gas in respect of the 0.44% non-controlling interest in Rosneft.

[f] Total proved gas reserves held as part of our equity interest in Rosneft is 9,271 billion cubic feet, comprising 1 billion cubic feet in Canada, 14 billion cubic feet in Venezuela, 31 billion cubic feet in Vietnam and 9,225 billion cubic feet in Russia.

Table of Contents

Movements in estimated net proved reserves continued

	million barrels	
Bitumen[a]		2013
	Rest of North America	Total
Subsidiaries		
At 1 January 2013		
Developed		
Undeveloped	**195**	**195**
	195	**195**
Changes attributable to		
Revisions of previous estimates	**(7)**	**(7)**
Improved recovery		
Purchases of reserves-in-place		
Discoveries and extensions		
Production		
Sales of reserves-in-place		
	(7)	**(7)**
At 31 December 2013		
Developed		
Undeveloped	**188**	**188**
	188	**188**

[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.

Table of Contents

Movements in estimated net proved reserves continued

million barrels of oil equivalent[b]

Total hydrocarbons[a]	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2013										
Developed	421	229	2,865	1	640	508		427	618	5,709
Undeveloped	546	103	1,504	195	1,110	587		209	445	4,699
	967	332	4,369	196	1,750	1,095		636	1,063	10,408
Changes attributable to										
Revisions of previous estimates	(89)	(27)	(342)	(5)	41	3		435	(36)	(20)
Improved recovery	20		161		25	7		81		294
Purchases of reserves-in-place	2									2
Discoveries and extensions			10			9		363	91	473
Production[d e]	(34)	(18)	(241)	(1)	(152)	(121)		(86)	(59)	(712)
Sales of reserves-in-place	(152)		(38)					(12)		(202)
	(253)	(45)	(450)	(6)	(86)	(102)		781	(4)	(165)
At 31 December 2013[f]										
Developed	280	225	2,525	2	564	486		582	735	5,399
Undeveloped	434	62	1,394	188	1,100	507		835	324	4,844
	714	287	3,919	190	1,664	993		1,417	1,059	10,243
Equity-accounted entities (BP share)[g]										
At 1 January 2013										
Developed					559	43	2,943	220		3,765
Undeveloped					508	39	2,265	15		2,827
					1,067	82	5,208	235		6,592
Changes attributable to										
Revisions of previous estimates				1	(20)	2	502	1		486

Improved recovery					38			1		39
Purchases of reserves-in-place					36		6,108	6		6,150
Discoveries and extensions					20		272			292
Production[e]					(55)	(1)	(353)	(88)		(497)
Sales of reserves-in-place					(92)		(5,204)	(13)		(5,309)
				1	(73)	1	1,325	(93)		1,161
At 31 December 2013[h i]										
Developed					552	50	3,782	133		4,517
Undeveloped				1	442	33	2,751	9		3,236
				1	994	83	6,533	142		7,753
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2013										
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
At 31 December 2013										
Developed	280	225	2,525	2	1,116	536	3,782	715	735	9,916
Undeveloped	434	62	1,394	189	1,542	540	2,751	844	324	8,080
	714	287	3,919	191	2,658	1,076	6,533	1,559	1,059	17,996

[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 72 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 5,500 barrels of oil equivalent per day.

[e] Includes 31 million barrels of oil equivalent of natural gas consumed in operations, 26 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities.

[f] Includes 551 million barrels of NGLs. Also includes 484 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[h] Includes 131 million barrels of NGLs. Also includes 30 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.

[i] Total proved reserves held as part of our equity interest in Rosneft is 6,574 million barrels of oil equivalent, comprising 1 million barrels of oil equivalent in Canada, 34 million barrels of oil equivalent in Venezuela, 5 million barrels of oil equivalent in Vietnam and 6,533 million barrels of oil equivalent in Russia.

Table of Contents

Movements in estimated net proved reserves continued

million barrels

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	Total
2012	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% non-controlling 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% non-controlling 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 4,454 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.

Table of Contents

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% non-controlling 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% non-controlling 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.

Table of Contents

Movements in estimated net proved reserves continued

		million barrels
Bitumen[a]		2012
	Rest of North America	Total
Subsidiaries		
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.

Table of Contents

Movements in estimated net proved reserves continued

million barrels of oil equivalent[b]

Total hydrocarbons[a]	Europe		North America		South America	Africa	Asia		Australasia	2012 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	178	1,173	665		342	455	5,556
	1,133	384	5,195	183	1,695	1,187		697	1,130	11,604
Changes attributable to										
Revisions of previous estimates	(33)	(27)	(600)	14	(31)	(3)		5	(8)	(683)
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)	13	55	(92)		(61)	(67)	(1,196)
At 31 December 2012[f j]										
Developed	421	229	2,865	1	640	508		427	618	5,709
Undeveloped	546	103	1,504	195	1,110	587		209	445	4,699
	967	332	4,369	196	1,750	1,095		636	1,063	10,408
Equity-accounted entities (BP share)[g]										
At 1 January 2012										
Developed					546		2,961	274		3,781
Undeveloped					522	48	1,727	66		2,363
					1,068	48	4,688	340		6,144
Changes attributable to										
Revisions of previous estimates					13	34	560	(19)		588

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)
					(1)	34	520	(105)		448
At 31 December 2012[h i k]										
Developed					559	43	2,943	220		3,765
Undeveloped					508	39	2,265	15		2,827
					1,067	82	5,208	235		6,592
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% non-controlling 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 non-controlling 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.

Table of Contents

Movements in estimated net proved reserves continued

million barrels

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	2011 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% non-controlling 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% non-controlling 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.

Table of Contents

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a]	Europe UK	Europe Rest of Europe	North America US	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2011 Total
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

[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% non-controlling 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% non-controlling 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.

Table of Contents

Movements in estimated net proved reserves continued

	million barrels	
Bitumen[a]		2011
	Rest of North America	Total
Subsidiaries		
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.

Table of Contents

Movements in estimated net proved reserves continued

million barrels of oil equivalent[b]

Total hydrocarbons[a]	Europe		North America		South America	Africa	Asia		Australasia	2011 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	179	1,192	779		371	462	5,775
	1,182	379	5,289	189	1,852	1,379		862	1,124	12,256
Changes attributable to										
Revisions of previous estimates	28	10	27	(3)	41	(103)		(119)	55	(64)
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)	(6)	(157)	(192)		(165)	6	(652)
At 31 December 2011[f]										
Developed	531	76	3,362	5	522	522		355	675	6,048
Undeveloped	602	308	1,833	178	1,173	665		342	455	5,556
	1,133	384	5,195	183	1,695	1,187		697	1,130	11,604
Equity-accounted entities (BP share)[g]										
At 1 January 2011										
Developed					593		2,716	382		3,691
Undeveloped					613	43	1,441	27		2,124
					1,206	43	4,157	409		5,815

Changes attributable to										
Revisions of previous estimates					(25)	5	795	(5)		770
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)
					(138)	5	531	(69)		329
At 31 December 2011[h i]										
Developed					546		2,961	274		3,781
Undeveloped					522	48	1,727	66		2,363
					1,068	48	4,688	340		6,144
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% non-controlling 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 non-controlling 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.

Table of Contents

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

	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2013										
Subsidiaries										
Future cash inflows[a]	**66,200**	**26,300**	**234,500**	**9,400**	**40,000**	**67,500**		**89,000**	**57,600**	**590,500**
Future production cost[b]	**21,900**	**11,200**	**99,000**	**4,600**	**11,600**	**17,800**		**35,000**	**20,000**	**221,100**
Future development cost[b]	**6,500**	**2,000**	**27,700**	**2,000**	**7,600**	**10,900**		**23,700**	**6,900**	**87,300**
Future taxation[c]	**23,900**	**8,000**	**37,000**	**400**	**11,100**	**14,300**		**6,200**	**8,100**	**109,000**
Future net cash flows	**13,900**	**5,100**	**70,800**	**2,400**	**9,700**	**24,500**		**24,100**	**22,600**	**173,100**
10% annual discount[d]	**6,800**	**2,200**	**34,300**	**1,900**	**4,200**	**9,300**		**13,300**	**12,800**	**84,800**
Standardized measure of discounted future net	**7,100**	**2,900**	**36,500**	**500**	**5,500**	**15,200**		**10,800**	**9,800**	**88,300**

cash flows[e]										
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]					**45,800**		**255,600**	**14,300**		**315,700**
Future production cost[b]					**22,500**		**139,000**	**11,800**		**173,300**
Future development cost[b]					**6,000**		**19,700**	**2,100**		**27,800**
Future taxation[c]					**5,900**		**15,200**	**100**		**21,200**
Future net cash flows					**11,400**		**81,700**	**300**		**93,400**
10% annual discount[d]					**6,900**		**48,700**	**100**		**55,700**
Standardized measure of discounted future net cash flows[g h]					**4,500**		**33,000**	**200**		**37,700**
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	**7,100**	**2,900**	**36,500**	**500**	**10,000**	**15,200**	**33,000**	**11,000**	**9,800**	**126,000**

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	**(30,600)**	**(7,900)**	**(38,500)**
Development costs for the current year as estimated in previous year	**14,000**	**3,200**	**17,200**
Extensions, discoveries and improved recovery, less related costs	**1,900**	**2,000**	**3,900**
Net changes in prices and production cost	**(1,800)**	**(100)**	**(1,900)**
Revisions of previous reserves estimates	**(3,100)**	**(400)**	**(3,500)**
Net change in taxation	**12,900**	**3,400**	**16,300**
Future development costs	**(4,100)**	**(2,100)**	**(6,200)**
Net change in purchase and sales of reserves-in-place	**(3,500)**	**9,000**	**5,500**
Addition of 10% annual discount	**9,300**	**2,800**	**12,100**
Total change in the standardized measure during the year[i]	**(5,000)**	**9,900**	**4,900**

[a] The marker prices used were Brent $108.02/bbl, Henry Hub $3.66/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] Non-controlling interest in BP Trinidad and Tobago LLC amounted to $1,700 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] Non-controlling interest in Rosneft amounted to $200 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.

Table of Contents

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserve continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2012
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		Total
At 31 December 2012										
Subsidiaries										
Future cash inflows[a]	88,000	30,800	261,100	9,500	30,400	75,800		54,200	54,300	604,100
Future production cost[b]	24,600	10,400	117,000	4,600	10,700	17,200		14,000	19,000	217,500
Future development cost[b]	7,400	2,400	29,600	2,400	7,700	13,000		10,900	3,700	77,100
Future taxation[c]	35,200	11,700	40,700	400	6,300	17,500		6,900	8,400	127,100
Future net cash flows	20,800	6,300	73,800	2,100	5,700	28,100		22,400	23,200	182,400
10% annual discount[d]	10,900	2,400	40,100	2,000	2,700	10,900		8,300	11,800	89,100
Standardized measure of discounted future net cash flows[e]	9,900	3,900	33,700	100	3,000	17,200		14,100	11,400	93,300
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]					49,400		203,600	24,400		277,400
Future production cost[b]					24,800		133,400	21,000		179,200

Future development cost[b]					5,500		16,600	1,900		24,000
Future taxation[c]					6,600		10,100	200		16,900
Future net cash flows					12,500		43,500	1,300		57,300
10% annual discount[d]					7,600		21,600	300		29,500
Standardized measure of discounted future net cash flows[g h]					4,900		21,900	1,000		27,800
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
			Total subsidiaries and
		Equity-accounted	equity-accounted
	Subsidiaries	entities (BP share)	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	14,400	3,100	17,500
Extensions, discoveries and improved recovery, less related costs	8,000	1,200	9,200
Net changes in prices and production cost	(15,300)	2,900	(12,400)
Revisions of previous reserves estimates	(16,000)	(1,000)	(17,000)
Net change in taxation	23,200	300	23,500
Future development costs	(7,700)	(500)	(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]	(23,200)	400	(22,800)

[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] Non-controlling 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] Non-controlling 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.

Table of Contents

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserve 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	9,200	39,100	82,100		59,200	53,900	710,700
Future production cost[b]	30,500	10,900	140,700	3,200	10,500	16,800		16,000	15,600	244,200
Future development cost[b]	8,500	2,700	32,300	1,900	7,600	13,200		9,600	3,200	79,000
Future taxation[c]	37,100	15,200	57,000	900	11,400	19,800		8,100	9,000	158,500
Future net cash flows	21,800	7,600	102,900	3,200	9,600	32,300		25,500	26,100	229,000
10% annual discount[d]	11,200	3,100	55,500	2,800	4,100	12,500		9,800	13,500	112,500
Standardized measure of discounted future net cash flows[e]	10,600	4,500	47,400	400	5,500	19,800		15,700	12,600	116,500
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]					46,700		188,900	34,200		269,800
Future production cost[b]					21,500		123,800	30,100		175,400
Future development cost[b]					5,000		15,600	2,400		23,000
Future taxation[c]					5,900		9,600	200		15,700

Future net cash flows					14,300		39,900	1,500		55,700
10% annual discount[d]					8,700		19,000	600		28,300
Standardized measure of discounted future net cash flows[g h]					5,600		20,900	900		27,400
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	13,200	2,500	15,700
Extensions, discoveries and improved recovery, less related costs	6,600	2,800	9,400
Net changes in prices and production cost	75,100	15,700	90,800
Revisions of previous reserves estimates	(21,900)	2,000	(19,900)
Net change in taxation	(18,200)	(1,400)	(19,600)
Future development costs	(11,000)	(2,500)	(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]	16,400	12,200	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] Non-controlling 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] Non-controlling 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.

Table of Contents

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 2013, 2012 and 2011.

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		
2013	**61**	**34**	**363**		**30**	**225**		**141**	**25**	**879**
2012	86	23	390	1	28	202		139	27	896
2011	113	32	453	2	39	190		138	25	992
Natural gas[c]								million cubic feet per day		
2013	**157**	**80**	**1,539**	**11**	**2,221**	**561**		**494**	**780**	**5,845**
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
Equity-accounted entities(BP share)										
Crude oil[b]								thousand barrels per day		
2013					**73**		**829**	**232**		**1,134**
2012					80		863	217		1,160
2011					90		865	210		1,165
Natural gas[c]								million cubic feet per day		
2013					**386**	**8**	**780**	**41**		**1,216**
2012					394		734	72		1,200
2011					392		699	34		1,125

[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.

Because of rounding, some totals may not exactly agree with the sum of their component parts.

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 2013. 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	
		UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Number of productive wells at 31 December 2013											
Oil wells[a]	gross	**115**	**63**	**2,456**	**55**	**4,681**	**608**	**41,541**	**2,166**	**13**	**5**
	net	**71**	**25**	**975**	**28**	**2,583**	**441**	**7,779**	**439**	**2**	**1**
Gas wells[b]	gross	**68**	**6**	**21,445**	**364**	**688**	**135**	**72**	**761**	**74**	**2**
	net	**29**	**1**	**9,367**	**179**	**239**	**52**	**14**	**280**	**14**	**1**
Oil and natural gas acreage at 31 December 2013											Thousa
Developed	gross	**128**	**39**	**6,340**	**223**	**1,634**	**621**	**4,380**	**1,982**	**162**	**1**
	net	**71**	**16**	**3,334**	**109**	**453**	**221**	**831**	**355**	**35**	
Undeveloped[c]	gross	**1,118**	**1,196**	**6,669**	**9,710**	**29,100**	**26,538**	**257,896**	**20,141**	**16,021**	**36**
	net	**672**	**403**	**4,585**	**7,638**	**12,943**	**17,142**	**50,285**	**7,258**	**11,254**	**11**

[a] Includes approximately 7,639 gross (1,491 net) multiple completion wells (more than one formation producing into the same well bore).

[b] Includes approximately 2,859 gross (1,350 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.

Table of Contents

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[e]	Rest of Asia		
2013										
Exploratory										
Productive	**1.0**		**12.7**		**4.5**	**1.5**	**4.0**	**3.5**		**27.2**
Dry			**1.1**		**1.4**	**0.6**		**0.9**	**0.5**	**4.5**
Development										
Productive	**1.0**	**1.2**	**285.7**		**94.6**	**12.6**	**395.0**	**58.0**	**0.2**	**848.3**
Dry		**0.2**	**0.4**		**2.7**	**0.2**		**0.7**	**0.4**	**4.6**
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

[e] Information for 2011 and 2012 includes BP s share of TNK-BP which was sold to Rosneft on 21 March 2013.

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 of 31 December 2013. 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 2013										
Exploratory										
Gross	**2.0**		**32.0**	**3.0**	**6.0**	**10.0**		**4.0**		**57.0**
Net	**0.8**		**9.2**	**1.5**	**2.2**	**5.2**		**0.8**		**19.7**
Development										
Gross	**6.0**	**3.0**	**780.0**	**55.0**	**33.0**	**20.0**	**100.0**	**58.0**	**10.0**	**1,065.0**
Net	**4.0**	**1.1**	**169.1**	**27.5**	**16.6**	**6.1**	**19.8**	**20.7**	**1.4**	**266.3**

Table of Contents

Pages 224-234 have been removed as they do not form part of

the BP s Annual Report on Form 20-F as filed with the SEC.

Table of Contents

Table of Contents

Selected financial information

This information, insofar as it relates to 2013, has been extracted or derived from the audited consolidated financial statements of the BP group presented on page 115. 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. Comparative financial information for 2009-12 has been restated to reflect the adoption of amendments to IAS 19 Employee Benefits . Financial information for 2011 and 2012 has also been restated to reflect the adoption of IFRS 11 Joint Arrangements . For further information see Financial statements Note 1.

$ million except per share amounts

	2013	2012	2011	2010	2009
Income statement data					
Sales and other operating revenues	**379,136**	375,765	375,713	297,107	239,272
Underlying replacement cost profit before interest and taxation[a]	**22,776**	26,454	33,601	31,704	22,673
Net favourable (unfavourable) impact of non-operating items and fair value accounting effects[a]	**9,283**	(6,091)	3,580	(37,190)	(169)
Replacement cost profit (loss) before interest and taxation[a]	**32,059**	20,363	37,181	(5,486)	22,504
Inventory holding gains (losses)[b]	**(290)**	(594)	2,634	1,784	3,922
Profit (loss) before interest and taxation	**31,769**	19,769	39,815	(3,702)	26,426
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(1,548)**	(1,638)	(1,587)	(1,605)	(1,609)
Taxation	**(6,463)**	(6,880)	(12,619)	1,638	(8,273)
Profit (loss) for the year	**23,758**	11,251	25,609	(3,669)	16,544
Profit (loss) for the year attributable to BP shareholders	**23,451**	11,017	25,212	(4,064)	16,363
Inventory holding (gains) losses[b], net of taxation	**230**	411	(1,800)	(1,195)	(2,623)
Replacement cost profit (loss) for the year attributable to BP shareholders[a]	**23,681**	11,428	23,412	(5,259)	13,740
Non-operating items and fair value accounting effects[a], net of taxation	**(10,253)**	5,643	(2,242)	25,436	622
Underlying replacement cost profit for the year attributable to BP shareholders[a]	**13,428**	17,071	21,170	20,177	14,362
Per ordinary share cents					
Profit (loss) for the year attributable to BP shareholders					
Basic	**123.87**	57.89	133.35	(21.64)	87.34
Diluted	**123.12**	57.50	131.74	(21.64)	86.40
Replacement cost profit (loss) for the year attributable to BP shareholders	**125.08**	60.05	123.83	(28.01)	73.34
Underlying replacement cost profit for the year attributable to BP shareholders	**70.92**	89.70	111.97	107.39	76.66
Dividends paid per share cents	**36.50**	33.00	28.00	14.00	56.00

pence	**23.399**	20.852	17.404	8.679	36.417
Capital expenditure and acquisitions[c]	**36,612**	25,204	31,959	23,016	20,309
Acquisitions and asset exchanges	**71**	200	11,283	3,406	308
Organic capital expenditure[d]	**24,600**	23,950	19,580	18,218	20,001
Balance sheet data (at 31 December)					
Total assets	**305,690**	300,466	292,907	272,262	235,968
Net assets	**130,407**	119,752	112,585	95,891	102,113
Share capital	**5,129**	5,261	5,224	5,183	5,179
BP shareholders equity	**129,302**	118,546	111,568	94,987	101,613
Finance debt due after more than one year	**40,811**	38,767	35,169	30,710	25,518
Net debt to net debt plus equity[e]	**16.2%**	18.7%	20.4%	21.2%	20.4%
Ordinary share data[f]					Shares million
Basic weighted average number of shares	**18,931**	19,028	18,905	18,786	18,732
Diluted weighted average number of shares	**19,046**	19,158	19,136	18,998	18,936

[a] RC profit or loss for the group, underlying RC profit or loss and fair value accounting effects are not recognized GAAP measures. For further information, see pages 237 and 238 and Certain definitions on page 269.

[b] See Certain definitions and also see Financial statements Note 7 for an analysis of inventory holding gains and losses by segment.

[c] 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.

[d] Organic capital expenditure excludes acquisitions and asset exchanges, and: in 2013 $11,941 million relating to our investment in Rosneft; 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 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.

[e] Net debt and the ratio of net debt to net debt plus equity are not recognized GAAP measures. We believe these numbers are useful information to investors. Further information on net debt is given in Financial statements Note 28.

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

Table of Contents

Non-operating items

Non-operating items are charges and credits arising in consolidated entities and in TNK-BP and Rosneft 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 to understand better and evaluate the group s reported financial performance. An analysis of non-operating items is shown in the table below.

			$ million
	2013	2012	2011
Upstream			
Impairment and gain (loss) on sale of businesses and fixed assets	**(802)**	3,638	2,131
Environmental and other provisions	**(20)**	(48)	(27)
Restructuring, integration and rationalization costs			
Fair value gain (loss) on embedded derivatives	**459**	347	191
Other[a]	**(1,001)**	(748)	(1,165)
	(1,364)	3,189	1,130
Downstream			
Impairment and gain (loss) on sale of businesses and fixed assets	**(348)**	(2,934)	(332)
Environmental and other provisions	**(134)**	(171)	(221)
Restructuring, integration and rationalization costs	**(15)**	(32)	(4)
Fair value gain (loss) on embedded derivatives			
Other	**(38)**	(35)	(45)
	(535)	(3,172)	(602)
TNK-BP			
Impairment and gain (loss) on sale of businesses and fixed assets	**12,500**	(55)	
Environmental and other provisions		(83)	
Restructuring, integration and rationalization costs			
Fair value gain (loss) on embedded derivatives			
Other[b]		384	
	12,500	246	
Rosneft			
Impairment and gain (loss) on sale of businesses and fixed assets	**(35)**		
Environmental and other provisions	**(10)**		
Restructuring, integration and rationalization costs			
Fair value gain (loss) on embedded derivatives			
Other			
	(45)		
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets	**(196)**	(282)	275
Environmental and other provisions	**(241)**	(261)	(220)
Restructuring, integration and rationalization costs	**(3)**	(15)	(39)
Fair value gain (loss) on embedded derivatives[c]			(123)
Other[d]	**19**	(240)	(715)
	(421)	(798)	(822)

Gulf of Mexico oil spill response	**(430)**	(4,995)	3,800
Total before interest and taxation	**9,705**	(5,530)	3,506
Finance costs[e]	**(39)**	(19)	(58)
Taxation credit (charge)[f]	**867**	251	(1,253)
Total after taxation	**10,533**	(5,298)	2,195

[a] 2013 included $845 million relating to the value ascribed to block BM-CAL-13 offshore Brazil, following the acquisition of upstream assets from Devon Energy in 2011, which was written off as a result of the Pitanga exploration well not encountering commercial quantities of oil or gas. 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] 2012 included dividend income from TNK-BP of $709 million and a charge of $325 million to settle disputes with AAR.

[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 for further details.

[f] For the Gulf of Mexico oil spill and certain impairment losses, disposal gains and fair value gains and losses on embedded derivatives, tax is based on statutory rates, except for non-deductible items. For other items reported for consolidated subsidiaries, tax is calculated using the group s discrete quarterly effective tax rate (adjusted for the items noted above, equity-accounted earnings and certain deferred tax adjustments relating to changes in UK taxation). Non-operating items reported within the equity-accounted earnings of TNK-BP and Rosneft 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 269.

			$ million
	2013	2012	2011
Upstream			
Unrecognized gains (losses) brought forward from previous period	**(404)**	(538)	(527)
Unrecognized (gains) losses carried forward	**160**	404	538
Favourable (unfavourable) impact relative to management s measure of performance	**(244)**	(134)	11
Downstream[a]			
Unrecognized gains (losses) brought forward from previous period	**501**	74	137
Unrecognized (gains) losses carried forward	**(679)**	(501)	(74)
Favourable (unfavourable) impact relative to management s measure of performance	**(178)**	(427)	63
	(422)	(561)	74
Taxation credit (charge)[b]	**142**	216	(27)
	(280)	(345)	47
By region			
Upstream			
US	**(269)**	(67)	15
Non-US	**25**	(67)	(4)
	(244)	(134)	11
Downstream[a]			
US	**(211)**	(441)	
Non-US	**33**	14	63
	(178)	(427)	63

[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, equity-accounted earnings, certain impairment losses, disposal gains and fair value gains and losses on embedded derivatives and certain deferred tax adjustments relating to changes in UK taxation).

Reconciliation of non-GAAP information

			$ million
	2013	2012	2011
Upstream			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**16,901**	22,625	26,347
Impact of fair value accounting effects	**(244)**	(134)	11

Replacement cost profit before interest and tax	**16,657**	22,491	26,358
Downstream			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	**3,097**	3,291	5,407
Impact of fair value accounting effects	**(178)**	(427)	63
Replacement cost profit before interest and tax	**2,919**	2,864	5,470
Total group			
Profit before interest and tax adjusted for fair value accounting effects	**32,191**	20,330	39,741
Impact of fair value accounting effects	**(422)**	(561)	74
Profit before interest and tax	**31,769**	19,769	39,815

Table of Contents

Upstream analysis by region

The following discussion reviews operations in our upstream business by geographical area, and lists associated significant events for 2013. BP s percentage working interest in oil and gas assets is shown in parentheses. 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.

In addition to exploration, development and production activities, our upstream business also includes midstream and LNG 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.

Our LNG supply activities are located in Abu Dhabi, Angola, Australia, Indonesia and Trinidad. We market around 25% of our LNG production using BP LNG shipping and contractual rights to access import terminal capacity in the liquid markets of the US (via Cove Point), the UK (via the Isle of Grain), Spain (in Bilbao) and Italy (in Rovigo), with the remainder marketed directly to customers. LNG is supplied to customers in multiple markets including Japan, South Korea, China, the Dominican Republic, Argentina, Brazil and Mexico.

Europe

In Europe, BP is active in the UK North Sea and the Norwegian Sea. Our activities in the North Sea include a focus on maximizing recovery from existing producing fields and selected new field developments.

- In January production from the new facilities at the Valhall field in the southern part of the Norwegian North Sea commenced and has now ramped up to 70 mboe/d. Production from Skarv, which started up in December 2012, has now ramped up to 160 mboe/d.
- In March BP and its partners, ConocoPhillips, Chevron and Shell, announced the decision to proceed with a two-year appraisal programme to evaluate a potential third phase of the Clair field, west of the Shetland Islands. By the end of 2013, two appraisal wells had been completed and we are currently drilling a third.
- In April we completed the sale of our interest in the Sean (BP 50%) field in the North Sea to SSE plc for $288 million.
- In June we completed the sales of our interests in the Harding (BP 70%), Maclure (BP 37.04%), Braes (BP 27.7%), Braemar (BP 52%) and Devenick (BP 88.7%) fields in the North Sea to TAQA Bratani Ltd for $1,058 million plus future payments which, depending on oil price and production, are currently expected to exceed $180 million after tax.
- In June BP announced that it had been awarded two licences in the Barents Sea as part of Norway s 22nd offshore licensing round.
- In August the Clair Ridge platform jackets (the steel support structure) were installed, a major milestone in the project.
- In September BP announced that more than $1.5 billion in contracts had been awarded to UK-based companies to provide services and equipment for the major redevelopment of the Schiehallion and Loyal oil fields to the west of Shetland. The project to redevelop the fields, which are operated by BP on behalf of its partners, involves two main elements: a new floating production, storage and offloading vessel (FPSO) and a major upgrade of the subsea infrastructure that will lie on the seabed.

In October the UK government announced a temporary management scheme to allow the restart of production from the Rhum gas field in the central North Sea, which has been suspended since November 2010 following the imposition of EU sanctions on Iran. The field is owned by BP (50%) and the Iranian Oil Company (IOC) under a joint operating agreement dating back to the early 1970s. BP intends to recommence operations at Rhum in the future in accordance with the temporary management scheme, under which the UK government will assume control of the IOC s share of Rhum for a period of up to five years. Revenue from the IOC s share will be placed in a blocked account. See Further note on certain activities on page 267 for further information.

In December BP was awarded 14 licences in the 27th UK Offshore Oil and Gas Licensing Round, subject to final government approval.

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 675mboe/d, with average throughput in 2013 of 421mboe/d. 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 2013 was 52mboe/d. CATS offers natural gas transportation and processing services. In addition, BP operates the Sullom Voe oil and gas terminal in Shetland.

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 BP s activities in connection with its responsibilities following the Deepwater Horizon oil spill, see page 38.

BP has around 620 lease blocks in the deepwater Gulf of Mexico, more than any other company, and operates four production hubs.

In 2013 BP started up an additional three rigs in the Gulf of Mexico, and by the end of the year had ten rigs in operation.

In April the Atlantis North expansion Phase 1 major project (BP 56%) started up.

In April we completed the sale of our interest in the Freedom (BP 31.5%) field in the Gulf of Mexico to Ecopetrol America.

In April the decision was taken not to move forward with the existing plan for the Mad Dog Phase 2 project in the deepwater Gulf of Mexico as market conditions and industry cost inflation made the project less attractive than previously modelled. This decision resulted in an impairment of $159 million. BP and its partners reviewed alternative development concepts and the current concept being considered is a single production host designed for future flexibility to capture additional potential resource.

In December BP announced it had made a significant oil discovery at its Gila prospect (BP 80%), which it co-owns with ConocoPhillips, in the deepwater Gulf of Mexico.

In February 2014 the Shell-operated Mars B major project (BP 28.5%) and the BP-operated Na Kika Phase 3 project (BP 50%) started up.

For information on the temporary suspension and mandatory debarment notices issued by the US Environmental Protection Agency (EPA) in November 2012 and February 2013 and related proceedings, see Legal proceedings on page 257.

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.

During 2013 BP participated in the drilling of several hundred wells as a non-operating partner in the Eagle Ford shale, Anadarko basin and Fayetteville shale. In the Eagle Ford shale BP, together with the operating partner, continued to expand its position, with around 450,000 gross acres at the end of 2013 and nine rigs operating. Production from the liquids-rich Anadarko basin is from over 1,000,000 gross acres, with around 12 rigs operating, and at Fayetteville there is an average of eight rigs running over the 145,000 gross acreage position.

In March 2014 we announced plans to establish a separate BP business to manage our onshore oil and gas assets in the US lower 48, with the goal of building a stronger, more competitive and sustainable business. We expect the separate organization to be operational in early 2015.

For further information on the use of hydraulic fracturing in our shale gas assets see page 45. BP s onshore US crude oil and product pipelines and related transportation assets are included in the Downstream segment (see page 31).

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.

Development of the Point Thomson initial production facility project continued throughout 2013. Engineering design is substantially complete, construction of field infrastructure is in progress and fabrication of the four main process modules has commenced. Overall, the project is on track. BP holds a 32% working interest in the Point Thomson field, and ExxonMobil is the operator.

Table of Contents

In June BP announced plans to add $1 billion of new investment over five years beginning 2015 in the Alaska North Slope fields by adding two additional drilling rigs, one each in 2015 and 2016. Changes in the state s oil tax statute helped to enable this increased investment. In addition, BP secured support from the other working interest owners at Prudhoe Bay to begin evaluating an additional $3 billion of new development opportunities, including facility expansions, a new well pad, and expansion of two existing well pads.

BP continued to work jointly with ExxonMobil, ConocoPhillips and TransCanada throughout 2013 to advance the Alaska LNG project. In February 2013 a lead concept for the project was announced, consisting of a North Slope gas treatment plant, an 800-mile (approximately) pipeline to tidewater and a three-train liquefaction facility, with an estimated capacity of 3bcf/d (15-18 million tonnes per annum). An initial summer field season to collect data that will support filing of necessary regulatory permits was completed. In October selection of the lead site for the liquefaction facility was announced as Nikiski, Alaska, located on the south-central Alaskan coast. In January 2014 BP, ExxonMobil, ConocoPhillips and TransCanada signed a heads of agreement (HOA) with the State of Alaska enabling state participation in the $45 $65 billion Alaska LNG project. The HOA sets out guiding principles for the parties to negotiate project-enabling contracts once enabling legislation is passed and provides a road map for state equity ownership in the project.

Also in Alaska, BP owns a 48.4% 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 non-controlling owners of TAPS, Koch (3.08%) and Unocal (1.37%) gave notice to BP, ExxonMobil (21.1%) and ConocoPhillips (29.1%) of their intention to withdraw as an owner of TAPS. The transfer of Koch s interest to the remaining owners (BP, ExxonMobil and ConocoPhillips) was agreed and approved by regulatory authorities, and closed in July with an effective date of August 2012. The remaining owners and Unocal have not yet reached agreement regarding the terms for the transfer of Unocal s interest in TAPS and are currently engaged in litigation.

In September 2012 BP, ExxonMobil and ConocoPhillips entered into two settlement agreements on the pooling of costs on TAPS. In July the Federal Energy Regulatory Commission (FERC) issued an order approving the two settlement agreements, and implementing cost pooling between TAPS owners under the terms of the settlement agreements.

In Canada, BP is currently focused on oil sands development and intends to use in situ steam-assisted gravity drainage (SAGD) technology, which 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 operation. In addition, we have significant exploration interests in the Canadian Beaufort Sea. The award of four offshore leases in Nova Scotia that were successfully bid for in 2012 was completed in 2013.

Phase 1 of the Sunrise Oil Sands SAGD development, in which we have a 50% non-operated interest, is under construction and is expected to commence operations in late 2014. The production capacity of Sunrise Phase 1 is expected to be 60mb/d of bitumen.

A major seismic programme on the Nova Scotia exploration leases is planned for the summer of 2014. The focus of the seismic programme will be to shoot 3D seismic on the 14,000km^2 lease area in depths ranging from 100 metres to 3,500 metres.

South America

In South America, BP has upstream activities in Brazil, Argentina, Bolivia, Chile, Uruguay and Trinidad & Tobago.

In Brazil, BP has interests in 24 exploration and production concessions, six of which are operated by BP, across six basins. Five of these concessions are subject to government and regulatory approvals.

- In March BP announced the completion of a successful flow test of the Itaipu-1A well, offshore Brazil. This activity was part of the ongoing appraisal programme and indicates that commercially viable flow rates can be achieved from the BP-operated Itaipu discovery, located in the deepwater sector of the Campos basin.
- In May BP and its partners announced they had been named winning bidders in eight deepwater blocks offshore Brazil in the Brazilian National Petroleum Agency s 11th bid round. BP will be operator of two of these blocks. Six of the blocks are in the Foz de Amazonas basin, with the remaining two in the Potiguar and Barreirinhas basins.
- In July BP announced the completion of an agreement with Petróleo Brasileiro S.A. (Petrobras) to farm in to five deepwater exploration and production blocks, subject to government and regulatory approvals. The blocks are in the deepwater Potiguar basin located in the Brazilian equatorial margin and in total cover an area of 3,837km^2.
- In December BP confirmed the Pitu oil discovery, operated by Petrobras, on block BM-POT-17 in the frontier deepwater of the Potiguar basin. BP s farm-in to a 40% interest in this block is subject to final regulatory approvals.
- In December BP announced the Pitanga exploration well on block BM-CAL-13 in the Camamu-Almada basin offshore Brazil had encountered oil shows but no commercial quantities of oil or gas. This result will cause BP to relinquish the block and triggered a write-off of $216 million related to the costs of drilling the well, as well as a write-off of $845 million associated with the value allocated to this block as part of the accounting related to the acquisition of Devon Energy s interest in the block announced in 2010.
- In January 2014 we completed the sale of our interest in the Polvo oil field (BP 60%) in Brazil to HRT Oil & Gas Ltda for $135 million.

In Argentina, Bolivia and Chile, BP conducts activity through Pan American Energy LLC (PAE), an equity-accounted joint venture with Bridas Corporation, in which BP has a 60% interest.

In Uruguay, BP has interests in three offshore deepwater exploration blocks: blocks 11 and 12 in the Pelotas basin and block 6 in the Punta del Este basin, together covering 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 is preparing to undertake its commitment to acquire over 13,000km^2 of 3D seismic data and 3,000km of 2D seismic data during the first exploration period which ends in December 2015.

In Trinidad & Tobago, BP holds licences covering 1,806,000 acres offshore of the east and north-east coast. Facilities include 13 offshore platforms and one onshore processing facility. Production is comprised of oil, gas and associated liquids.

BP has a shareholding in Atlantic LNG (ALNG), an LNG liquefication plant, in Trinidad & Tobago that averages 39% across four LNG trains[a] with a combined capacity of 21 million tonnes per annum. BP sells gas to each of the LNG trains, supplying 100% of the gas for train 1, 50% for train 2, 75% for train 3 and around 67% of the gas for train 4. 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 Europe under long-term contracts. BP s equity LNG entitlement from trains 2, 3 and 4 is marketed via BP s LNG marketing and trading function to markets in the US, UK, Spain and South America.

Africa

BP s upstream activities in Africa are located in Angola, Algeria, Libya, Morocco, Egypt and Namibia.

BP is present in nine major deepwater licences offshore Angola and is operator in four of these.

Production from the Plutão, Saturno, Vénus and Marte (PSVM) development area in Block 31, offshore Angola, which started production in late 2012, continued to increase as planned, reaching a maximum rate of just over 150mb/d in 2013.

In October we had an oil and gas discovery in the pre-salt play of Angola in Block 20 (BP 30%), operated by Cobalt International Energy, Inc. This was followed by a successful drill-stem test in December.

[a] An LNG train is a processing facility used to liquefy and purify natural gas in the formation of LNG.

Table of Contents

In addition, BP has a 13.6% share in the Angola LNG project, which is expected to receive approximately 1bcf 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 project exported its first cargo of LNG in June.

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 has an appraisal and exploitation agreement with Sonatrach in the Bourarhat Sud block, located to the south-west of In Amenas. In the exploration phase this asset is BP-operated. The Bourarhat licence has been extended until September 2014 and BP is currently assessing its options to appraise and potentially develop this asset. BP s total assets in Algeria at 31 December 2013 were $3,413 million ($324 million current and $3,089 million non-current).

In January a terrorist attack occurred at the In Amenas joint operation site. Following the incident, BP had a staged reduction of non-essential workers out of Algeria as a precautionary and temporary measure. Trains 1 and 2 have been restored to full production but Train 3 remains out of service. In March, the decision was taken to suspend activity at Bourarhat while options to appraise and potentially develop this asset are assessed. Ramp-down of activity was largely completed in October.

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 2013 were $472 million ($72 million current and $400 million non-current).

Planning and preparation work towards our offshore exploration drilling programme is continuing. With respect to the onshore exploration drilling programme, a security review in June concluded that this could not be safely and securely delivered by BP at this time. Alternative approaches are being considered.

In Morocco, BP entered into three farm-out agreements with Kosmos Energy covering three blocks in the Agadir Basin, offshore Morocco. Under the terms of the agreements, one of which is still subject to government approval, BP will acquire a non-operating interest in each of the Essaouira Offshore (BP 45%), Foum Assaka Offshore (BP 26.325%) and Tarhazoute Offshore (BP 45%) blocks.

In Egypt, BP and its partners currently produce 15% of Egypt s oil production and more than 30% of its gas production. BP s total assets in Egypt at 31 December 2013 were $7,638 million, of which $2,299 million were current (see Financial statements Note 19) and $5,339 million were non-current.

In July the Egyptian army chief removed the country s then-incumbent president, Mohamed Morsi, from power and suspended the Egyptian Constitution. Adly Mansour, Chief Justice of the Supreme Constitutional Court of Egypt was declared interim president. The political and economic situation remains challenging despite aid being pledged from neighbouring Gulf states. Our production and operations continue and we are engaged with the government in managing our operations.

In September BP announced a significant gas discovery in the East Nile Delta with the Salamat well, the deepest well ever drilled in the Nile Delta. Salamat is the first well to be drilled in the BP-operated North Damietta (BP 100%) offshore concession awarded in 2010.

In Namibia, BP is a non-operating partner in one deepwater block, which is currently in the exploration phase. This block was accessed in 2012. In December BP decided to withdraw from four deepwater blocks by not exercising an option to increase its interest in Luderita Basin licence 0047, offshore Namibia.

Asia

In Asia, BP has activities in Western Indonesia, China, Azerbaijan, Oman, Abu Dhabi, India and Iraq.

In Western Indonesia, BP is involved in two of Indonesia s three LNG centres. BP s first operated LNG plant, Tangguh (BP 37.16%), is located

in Papua Barat. The asset comprises 14 producing wells, two offshore platforms, two pipelines and an LNG plant with two production trains and has a total capacity of 7.6 million tonnes of LNG per annum. Plans for a third train remain on track, with commissioning projected to occur in 2019. Tangguh supplies LNG to customers in China, South Korea, Mexico and Japan through a combination of long, medium and short-term contracts.

BP also participates in Indonesia s LNG exports through its interest in Virginia Indonesia Company LLC (VICO), the operator of Sanga-Sanga PSA (BP 38%) supplying gas to the Bontang LNG plant in Kalimantan. Sanga-Sanga currently delivers around 13% of the total gas feed to Bontang, Indonesia s largest LNG export facility and one of the world s largest LNG plants with a capacity of 22 million tonnes per annum of LNG and output of more than 18 million tonnes of LNG.

BP also participates in the Sanga-Sanga CBM PSA (BP 38%), as well as one other CBM PSA, Tanjung IV (BP 44%), in the Barito basin of Central Kalimantan. BP completed its exit from the Kapuas I, II and III PSAs in May by transfer of its working interest to its respective partner in each PSA.

In China, BP s upstream activities in the country include deepwater exploration in the South China Sea s Block 42/05 (BP 40.82%), Block 43/11 (BP 40.82%) and Block 54/11 (BP 100%).

- In July BP announced that it had signed a PSA with CNOOC for Block 54/11 in the South China Sea. The new block is close to BP s two other existing deepwater interests.
- In December we completed the sale of our interests in the Yacheng offshore gas field (BP 34.3%) in China for $308 million (subject to post-closing adjustments).

In China, BP also 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 first foreign partner in China s LNG import business. The terminal is also supplied under a long-term contract with Australia s North West Shelf venture described below.

In Azerbaijan, BP invests more than any other foreign investor, operates two PSAs, Azeri-Chirag-Gunashli (ACG) (BP 35.8%) and Shah Deniz (BP 25.5%), and also holds other exploration leases.

- In 2012 further EU and US regulations concerning restrictive measures against Iran were issued. The Shah Deniz joint operation and its gas marketing and pipeline entities, in which Naftiran Intertrade Co. Ltd (NICO) has an interest, 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 the US Iran Threat Reduction and Syria Human Rights Act of 2012. Shah Deniz continues to operate in full compliance with EU and US law. For further information see Further note on certain activities on page 267.

In June the Shah Deniz consortium announced that it had selected the Trans Adriatic Pipeline (TAP) to deliver gas volumes from the Shah Deniz Stage 2 project to customers in Italy, Greece, Bulgaria and Turkey. In September, the consortium announced that it had concluded the Shah Deniz Stage 2 gas sales process with the completion of major sales agreements with European gas purchasers totalling 10bcma over 25 years. This adds to existing agreements to sell 6bcma of gas in Turkey. The agreements come in to force following the final investment decision (FID) on the project, which occurred in December. The upstream part of the Shah Deniz Stage 2 project entails drilling and completion of 26 subsea wells, construction of two bridge-linked platforms and new processing and compression facilities at the onshore terminal. The FID also triggers plans to expand the South Caucasus Pipeline (SCP) through Azerbaijan and Georgia, to construct the Trans Antolian Gas Pipeline (TANAP) across Turkey and to construct the TAP across Greece, Albania and into Italy.

Additionally, the State Oil Company of Azerbaijan Republic (SOCAR) and the Shah Deniz partners also agreed terms for extending the Shah Deniz PSA to 2048 and, coincident with the FID, BP agreed to purchase a 3.3% equity in Shah Deniz and SCP from Statoil, subject to conditions that are expected to be satisfied in 2014.

In January 2014 the West Chirag platform came online. This completes the Chirag oil project sanctioned in 2010.

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 and gas condensate from the Shah Deniz gas field in the Caspian Sea, along with other third-party oil, to the eastern Mediterranean port of Ceyhan. The BTC pipeline has a capacity of 1mmboe/d with average throughput in 2013 of 681mboe/d.

BP is technical operator of, and currently 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 2013 of 82mboe/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).

BP currently has appraisal programmes and development activities in Oman.

In December BP and the Sultanate of Oman government signed a gas sales agreement and an amended exploration and production sharing agreement (EPSA) for the development of the Khazzan field in Block 61 with BP as operator. In February 2014 the Sultan of Oman issued a royal decree approving the amended EPSA. The Sultanate of Oman government acquired a 40% stake in Block 61 in February 2014 through Makarim Gas Development LLC, a wholly-owned subsidiary of the state-owned Oman Oil Company Exploration & Production (OOCEP). Construction work is expected to begin in 2014 with gas production expected to start in 2017.

In Jordan BP has decided to withdraw from the Risha concession, which resulted in a write-off of $121 million related to the costs of exploration drilling activities, as well as a $257-million write-off for costs relating to the concession.

In Abu Dhabi, during 2013 we had equity interests of 9.5% and 14.67% in onshore and offshore concessions respectively. The Abu Dhabi onshore concession expired in January 2014 with a consequent production impact of approximately 140mboe/d.

Also in Abu Dhabi, we have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2013 supplied 5.4 million tonnes of LNG (281 bcfe regasified).

In India, BP has a 30% interest in six 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 operation for the sourcing and marketing of gas in India.

In May RIL and its partners BP and NIKO Resources Ltd announced a significant gas and condensate discovery in the KG D6 block off the eastern coast of India.

In August RIL and BP announced a new gas condensate discovery in the deepwater block CYD5 (BP 30%) situated in the Cauvery basin, off the east coast of India. This is the second discovery in the block.

In August the government approved the Field Development Plan (FDP) for the R-Series project in the KG D6 block and has reviewed the appraisal plan for the KG D6 discovery.

Following approval by the relevant authorities in 2012, a number of activities are being progressed to arrest the decline in production rates and to extend the life of the block KG D6 producing fields. These include new work-over wells and the installation of additional compression and water handling capacity.

In January 2014 the Government of India issued notification of new guidelines for pricing of domestic gas, which will be formula driven, effective from 1 April 2014.

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 in operation. BP s net share of the capacity of NWS LNG trains 1-5 is 2.7 million tonnes per annum of LNG.

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.

BP holds a 70% interest in four deepwater offshore exploration blocks in the Ceduna Sub Basin (this follows the farm-down of 30% of our interest in the four blocks to Statoil in April). BP, as operator, expects to drill four deepwater wells beginning in 2016 in this frontier exploration basin, located within the Great Australian Bight off the coast of southern Australia.

BP is also one of five partners in the Browse LNG venture (operated by Woodside) and holds a 17% interest.

- In September the Browse joint operation partners decided to change the concept from an onshore LNG plant at James Price Point to an offshore floating LNG concept resulting in an impairment of $251 million. The proposed development remains subject to regulatory, joint operation and internal BP approvals.
- In September gas production commenced at the Woodside-operated North Rankin Phase 2 compression platform, designed to extend the life of the North West Shelf production to 2040.

In Eastern Indonesia, BP has 100% interests in two deepwater PSAs: West Aru I and II. The PSAs are located 200 kilometres west of the Aru island group. A seismic campaign covering 5,000km^2 in the West Aru PSAs was completed in September. In addition, BP owns a 32% interest in the Chevron-operated West Papua I and Ill PSAs, located 120 kilometres to the south of our Tangguh LNG plant (BP 37.16% and operator).

BP received approval from the government of the Republic of Indonesia in November to transfer its 100% interest in the North Arafura PSA, located on the coast of the Arafura Sea, 480 kilometres south east of the Tangguh LNG plant.

Downstream analysis by region

The downstream business includes our global fuels, lubricants and petrochemicals businesses. We have significant operations in Europe, North America and Asia, and also manufacture and market our products across Australasia, Southern Africa and Central and South America.

We made significant progress in our plans to reshape the US fuels business, build new capability and improve technology in 2013.

Our downstream business operations are detailed below by geographical area with associated significant events for 2013.

North America

BP is active in North America through our refineries, terminals, pipelines, retail sites, lubricants, aviation and petrochemical plants.

To improve production, increase capacity or reduce unit cost we built and reconfigured major units at three refineries.

- Whiting refinery commissioning of all major units of the Whiting refinery modernization project was completed in December 2013. As part of the project, we built or reconfigured almost every process unit, including crude distillation and coking units as well as hydro-treating sulphur recovery and coking capacity. The upgrade increases the refinery s heavy oil processing capability, enabling processing of up to 80% of heavy, sour crude. Whiting s Midwest location provides advantaged access to heavy Canadian crudes and access to three major geographic crude sources.
- Toledo refinery BP-Husky Refining LLC successfully started up a new naphtha reformer in March 2013. It is intended to improve the plant s efficiency and competitiveness and reduce refinery air emissions.
- Cherry Point refinery We completed a state-of-the-art diesel hydrotreater and hydrogen plant in May 2013. The units enhance our ability to meet regulations calling for lower sulphur diesel fuel.

Table of Contents

We continued to reshape our US fuels business by completing the sales of the Texas City and Carson, California refineries, as well as related logistics and marketing assets.

Our Decatur petrochemicals paraxylene/PTA plant will be the principal supplier for a new adjacent 432,000 ton PET resin facility of Indorama Polymers Group, announced in August 2013.

Europe

We announced two new proprietary petrochemicals technologies, *SaaBre* and *Hummingbird*. Both technologies are expected to deliver significant reductions in variable manufacturing costs and simplify the global manufacturing process.

SaaBre significantly reduces the cost of production of acetic acid from syngas and avoids the need to purify carbon monoxide or purchase methanol. *SaaBre* technology could also be used to produce methanol and ethanol.

Hummingbird simplifies the process of converting ethanol to ethylene, a key component for the manufacture of plastics. *Hummingbird* could open the way for the production of biopolymers from bioethanol.

We have completed the sale of six out of eight countries of our global LPG marketing business, which sells bulk and bottled LPG products (UK, Benelux, Austria, Poland, Turkey and South Africa). Sales of the remaining businesses in Portugal and China are expected to be completed in 2014.

Our lubricants business announced a co-operation agreement with Honda Motor Europe to be the recommended lubricants supplier for Honda s European franchise car dealer network.

Africa

We announced our intention to invest more than $500 million in southern Africa over the next five years. Around half of this investment will be used to upgrade refinery infrastructure at SAPREF, BP s joint operation with Shell located in Durban. In addition, BP will invest in Pick n Pay™ retail network in South Africa and in building and upgrading our fuel terminals to a world-class standard in Mozambique and South Africa.

Asia

Construction of our third PTA plant at Zhuhai in Guangdong province of China progressed, with completion expected in late 2014.

In December 2013 we agreed to purchase all interests held by our partners, Mitsui Chemicals, Inc. and Mitsui & Co. Ltd. in PT Amoco Mitsui PTA Indonesia which produces and markets PTA in the Republic of Indonesia. This transaction completed on 28 February 2014 and is consistent with our strategy of growing our PTA business in our chosen markets.

We launched the gasoline additive, *Ultimate,* in China. The aim is to create new market opportunities to capture more of the passenger car market in China.

Downstream plant capacity

The following table summarizes the BP group s interests in refineries and average daily crude distillation capacities as at 31 December 2013.

thousand barrels per day

Geographical area	Refinery	Fuels value chain	Group interest[b] %	Crude distillation capacities[a] Total	BP share
US					
Washington	Cherry Point	US North West	100.0	234	234
Indiana	Whiting	US East of Rockies	100.0	428	428
Ohio	Toledo	US East of Rockies	50.0	160	80
				822	742
Europe					
Germany	Bayernoil[c]	Rhine	22.5	217	49
	Gelsenkirchen	Rhine	50.0	265	132
	Karlsruhe[c]	Rhine	12.0	322	39
	Lingen	Rhine	100.0	95	95
	Schwedt[c]	Rhine	18.8	239	45
Netherlands	Rotterdam	Rhine	100.0	377	377
Spain	Castellón	Iberia	100.0	110	110
				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[c]	Australia New Zealand	23.7	118	28
South Africa	Durban[c]	Southern Africa	50.0	180	90
				546	366
Total BP share of capacity at 31 December 2013					1,955

[a] Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.
[b] BP share of equity, which is not necessarily the same as BP share of processing entitlements.
[c] Indicates refineries not operated by BP.

Table of Contents

Petrochemicals production capacity[a b]

The following table summarizes the BP group s share of petrochemicals production capacities as at 31 December 2013.

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 2013				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.
[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%.

Table of Contents

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 PUD 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 resources.

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 2013 BP had material volumes of proved undeveloped reserves held for more than five years in Trinidad and the Gulf of Mexico. These are part of ongoing development activities for which BP has a historical track record of completing comparable projects in these countries. We have no proved undeveloped reserves held for more than five years in our onshore US developments.

In each case 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 19% of our proved undeveloped reserves (accounting for 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 2013 we progressed 985mmboe of proved undeveloped reserves (532mmboe for our subsidiaries alone) to proved developed reserves through ongoing investment in our subsidiaries and equity-accounted entities upstream development activities. Total development expenditure in Upstream, excluding midstream activities, was $16,664 million in 2013 ($13,552 million for subsidiaries and $3,112 million for equity-accounted entities). The major areas with progressed volumes in 2013 were Angola, Australia, Azerbaijan, Iraq, Norway, Russia, Trinidad and the US. Revisions of previous estimates for proved undeveloped reserves are due to changes relating to field performance or well results. The following tables describe the changes to

our proved undeveloped reserves position through the year for our subsidiaries and equity-accounted entities and for our subsidiaries alone.

Subsidiaries and equity-accounted assets	volumes in mmboe
Proved undeveloped reserves at 1 January 2013	7,526
Revisions of previous estimates	466
Improved recovery	333
Discoveries and extensions	765
Purchases	2,447
Sales	(2,472)
Total in year proved undeveloped reserves changes	9,065
Progressed to proved developed reserves	(985)
Proved undeveloped reserves at 31 December 2013	8,080

Subsidiaries only	volumes in mmboe
Proved undeveloped reserves at 1 January 2013	4,699
Revisions of previous estimates	(20)
Improved recovery	294
Discoveries and extensions	473
Purchases	
Sales	(70)
Total in year proved undeveloped reserves changes	5,376
Progressed to proved developed reserves	(532)
Proved undeveloped reserves at 31 December 2013	4,844

BP bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements. 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.

Group 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.

BP s vice president of segment reserves is the petroleum engineer primarily responsible for overseeing the preparation of the reserves estimate. He has more than 30 years of diversified industry experience with the past nine 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.

No specific portion of compensation bonuses for executive directors and senior management 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 with the exception of those proved reserves held by our Russian equity-accounted entity, Rosneft are estimated by the group s petroleum engineers.

DeGolyer & MacNaughton (D&M), an independent petroleum engineering consulting firm, has estimated the net proved crude oil, condensate, natural gas liquids (NGLs) and natural gas reserves, as of 31 December 2013, of certain properties owned by Rosneft. The properties evaluated by D&M account for 100% of Rosneft s net proved reserves as of 31 December 2013. The net proved reserves estimates prepared by D&M were prepared in accordance with the reserves definitions of Rule 4-10(a)(1)-(32) of Regulation S-X. All reserves estimates involve some degree of uncertainty. BP has filed D&M s independent report on its reserves estimates as an exhibit to this document.

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 (joint ventures 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-three per cent of our total proved reserves of subsidiaries at 31 December 2013 were held through joint operations (82% in 2012), and 31% of the proved reserves were held through such joint operations where we were not the operator (31% in 2012).

Estimated net proved reserves of liquids at 31 December 2013[a b c]

			million barrels
	Developed	Undeveloped	Total
UK	169	380	549
Rest of Europe	163	55	218
US	1,297	907	2,204[d]
Rest of North America		188	188
South America	29	45	74[e]
Africa	320	195	515
Rest of Asia	320	202	522
Australasia	57	22	79
Subsidiaries	2,355	1,994	4,349
Equity-accounted entities	3,510	2,211	5,721[f]
Total	5,865	4,205	10,070

Estimated net proved reserves of natural gas at 31 December 2013[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	643	314	957
Rest of Europe	364	39	403
US	7,122	2,825	9,947
Rest of North America	10		10
South America	3,109	6,116	9,225[g]
Africa	961	1,807	2,768
Rest of Asia	1,519	3,671	5,190
Australasia	3,932	1,755	5,687
Subsidiaries	17,660	16,527	34,187
Equity-accounted entities	5,837	5,951	11,788[h]
Total	23,497	22,478	45,975

Net proved reserves on an oil equivalent basis

	million barrels of oil equivalent		
	Developed	Undeveloped	Total
Subsidiaries	5,399	4,844	10,243
Equity-accounted entities	4,517	3,236	7,753
Total	9,916	8,080	17,996

[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 non-controlling interests in consolidated operations. We disclose our share of reserves held in joint ventures and associates that are accounted for by the equity method although we do not control these entities or the assets held by such entities.

[b] The 2013 marker prices used were Brent $108.02/bbl (2012 $111.13/bbl and 2011 $110.96/bbl) and Henry Hub $3.66/mmBtu (2012 $2.75/mmBtu and 2011 $4.12/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 72 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 21 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[f] Includes 23 million barrels of crude oil in respect of the 0.47% non-controlling interest in Rosneft held assets in Russia.

[g] Includes 2,685 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[h] Includes 41 billion cubic feet of natural gas in respect of the 0.44% non-controlling interest in Rosneft held assets in Russia.

Table of Contents

Proved reserves replacement

Total hydrocarbon proved reserves, on an oil equivalent basis including equity-accounted entities, comprised 17,996mmboe (10,243mmboe for subsidiaries and 7,753mmboe for equity-accounted entities) at 31 December 2013, an increase of 6% (decrease of 2% for subsidiaries and increase of 18% for equity-accounted entities) compared with the 31 December 2012 reserves of 17,000mmboe (10,408mmboe for subsidiaries and 6,592mmboe for equity-accounted entities). Natural gas represented about 44% (58% for subsidiaries and 26% for equity-accounted entities) of these reserves. The change includes a net increase from acquisitions and disposals of 641mmboe (200mmboe net decrease for subsidiaries and 841mmboe net increase for equity-accounted entities). Net divestments in our subsidiaries occurred in the UK, the US, China and Canada. We had sales and purchases as a consequence of our divestment of TNK-BP and acquisition of Rosneft.

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 2013, the proved reserves replacement ratio excluding acquisitions and disposals was 129% (77% in 2012 and 103% in 2011) for subsidiaries and equity-accounted entities, 105% for subsidiaries alone and 164% for equity-accounted entities alone. Including the net growth in our Russian portfolio as a result of the change in our holdings, but excluding other acquisitions and disposals, the reserves replacement ratio on a combined basis was 199%. The net growth in our Russian portfolio relates only to equity-accounted entities (the transaction we completed during the year resulted in the disposal of our interest in TNK-BP and the acquisition of an interest in Rosneft). Therefore the split of this ratio between subsidiaries and equity-accounted entities is as follows. For subsidiaries alone it is

105%, the same amount as disclosed above. For equity-accounted entities alone it is 334%. BP reported its share of production and reserves for TNK-BP until the transaction completed on 21 March 2013, and this is reflected in the equity-accounted entities and group ratios disclosed above.

In 2013 net additions to the group s proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 1,564mmboe (747mmboe for subsidiaries and 817mmboe 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 2013 principally resulted from the application of conventional technologies. The principal proved reserves additions in our subsidiaries were in Angola, Azerbaijan, Indonesia, Iraq, Oman, India and Trinidad. We had material proved reserves reductions in the UK and the US due to changes in activity and performance updates. The principal reserves additions in our equity-accounted entities were in Argentina and Russia.

Fifteen per cent of our proved reserves are associated with PSAs. The countries in which we operated under PSAs in 2013 were Algeria, Angola, Azerbaijan, Egypt, India, Indonesia, Oman 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 expired in January 2014 with a consequent reduction in production of approximately 140mboe/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 207.

BP s net production by major field liquids

thousand barrels per day

	Field or area	BP net share of production[a] 2013	2012	2011
Subsidiaries				
UK[b]	ETAP[c]	**22**	11	22
	Foinaven (BP-operated)	**17**	14	26
	Other	**22**	61	65
Total UK		**61**	86	113
Norway[b]	Various	**34**	23	32
Total Rest of Europe		**34**	23	32
Total Europe		**96**	109	145
Alaska[b]	Greater Prudhoe Bay (BP-operated)	**73**	77	78
	Kuparuk	**36**	36	39
	Milne Point (BP-operated)	**16**	15	19
	Other	**12**	11	17
Total Alaska		**137**	139	153
Lower 48 onshore[b]	Various	**56**	60	69
Gulf of Mexico deepwater[b]	Great White	**23**	19	9
	Thunder Horse (BP-operated)	**27**	49	77
	Atlantis (BP-operated)	**40**	23	34
	Mad Dog (BP-operated)	**18**	9	8
	Mars	**14**	15	19
	Na Kika (BP-operated)	**28**	21	14
	Horn Mountain (BP-operated)		6	8
	King (BP-operated)		14	15
	Other	**20**	35	47
Total Gulf of Mexico deepwater		**170**	191	231
Total US		**363**	390	453
Canada[b]	Various (BP-operated)		1	2
Total Rest of North America			1	2
Total North America		**363**	391	455

Table of Contents

BP s net production by major field liquids continued

		thousand barrels per day		
		BP net share of production[a]		
	Field or area	**2013**	2012	2011
Subsidiaries				
Colombia[b]	Various (BP-operated)			1
Trinidad & Tobago	Various (BP-operated)	**23**	21	31
Brazil[b]	Polvo	**7**	7	7
Total South America		**30**	28	39
Angola	Greater Plutonio (BP-operated)	**59**	59	51
	Kizomba C Dev	**9**	9	21
	Dalia	**11**	11	12
	Girassol FPSO	**11**	11	12
	Pazflor	**32**	29	5
	PSVM	**24**	1	
	Other	**34**	29	22
Total Angola		**180**	149	123
Egypt	Gupco	**29**	32	34
	Other	**9**	9	11
Total Egypt		**38**	41	45
Algeria[b]	Various	**7**	12	22
Total Africa		**225**	202	190
Azerbaijan[b]	Azeri-Chirag-Gunashli (BP-operated)	**83**	82	86
	Other	**13**	10	8
Total Azerbaijan		**96**	92	94
Western Indonesia	Various	**1**	1	2
Iraq	Rumaila	**39**	39	31
Other	Various	**5**	7	11
Total Rest of Asia[b]		**141**	139	138
Total Asia		**141**	139	138
Australia	Various	**23**	24	23
Other	Various	**2**	3	2
Total Australasia		**25**	27	25
Total subsidiaries[d]		**879**	896	992
Equity-accounted entities (BP share)				
TNK-BP (Russia, Venezuela, Vietnam)[b e]	Various	**187**	877	871
Rosneft (Russia, Canada, Venezuela, Vietnam)[b f]	Various	**650**		
Abu Dhabi[g]	Various	**231**	216	209
Argentina	Various	**63**	65	74
Bolivia	Various	**2**	1	
Venezuela[b]	Various			10
Other	Various	**1**	1	1

Total equity-accounted entities	**1,134**	1,160	1,165
Total subsidiaries and equity-accounted entities	**2,013**	2,056	2,157

[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 2013, BP divested its interests in TNK-BP, its interests in the Harding, Devenick, Maclure, Braes and Braemar fields in the North Sea and its interests in the US onshore Moxa upstream operation in Wyoming. It also acquired an interest in Rosneft. In 2012, BP divested its interests in the Gulf of Mexico Marlin, Dorado, King, Horn Mountain, Holstein, Ram Powell and Diana Hoover assets, a portion of its interest in the 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 arrangement with Reliance, Brazil and additional volumes in the Gulf of Mexico and UK North Sea. BP divested its holdings in Pompano along with other interests in the 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.

[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] Includes 5.5 net mboe/d of NGLs from processing plants in which BP has an interest (2012 13.5mboe/d and 2011 28mboe/d).

[e] Estimated production for 2013 represents BP s share of TNK-BP s estimated production from 1 January to 20 March, averaged over the full year.

[f] 2013 reflects production for the period 21 March to 31 December, averaged over the full year.

[g] In 2013 BP held interests, through associates, in onshore and offshore concessions in Abu Dhabi, of which the onshore concession expired in 2014 and the offshore concession expires in 2018.

Because of rounding, some totals may not agree exactly with the sum of their component parts.

Table of Contents

BP s net production by major field natural gas

	Field or area	million cubic feet per day BP net share of production[a] 2013	2012	2011
Subsidiaries				
UK[b]	Bruce/Rhum (BP-operated)	**25**	15	20
	Other	**132**	399	335
Total UK		**157**	414	355
Norway	Various	**80**	8	13
Total Rest of Europe		**80**	8	13
Total Europe		**237**	422	368
Lower 48 onshore[b]	San Juan (BP-operated)	**529**	561	603
	Jonah (BP-operated)		69	145
	Anadarko	**129**	142	141
	Arkoma Central	**107**	118	136
	Wamsutter (BP-operated)	**159**	141	122
	Arkoma East	**115**	112	115
	Arkoma West	**110**	98	109
	Other	**255**	258	274
Total Lower 48 onshore		**1,404**	1,499	1,645
Gulf of Mexico deepwater[b]	Various	**114**	134	176
Alaska	Various	**21**	18	22
Total US		**1,539**	1,651	1,843
Canada[b]	Various	**11**	13	14
Total Rest of North America		**11**	13	14
Total North America		**1,551**	1,664	1,857
Trinidad & Tobago	Mango (BP-operated)	**119**	181	308
	Cashima/NEQB (BP-operated)	**138**	305	570
	Kapok (BP-operated)	**358**	360	464
	Cannonball (BP-operated)	**27**	56	99
	Amherstia (BP-operated)	**257**	324	296
	Serrette (BP-operated)	**527**	367	35
	Savonette (BP-operated)	**545**	320	327
	Immortelle (BP-operated)	**200**	95	68
	Other (BP-operated)	**50**	89	26
Total Trinidad		**2,221**	2,097	2,193
Colombia[b]	Various			4
Total South America		**2,221**	2,097	2,197
Egypt	Temsah	**30**	34	74
	Ha py (BP-operated)	**72**	88	99
	Taurt (BP-operated)	**50**	67	61
	Denis	**99**	138	77
	Other	**193**	143	133

Total Egypt		**444**	470	444
Algeria	Various	**117**	120	114
Total Africa		**561**	590	558
Pakistan[b]	Various (BP-operated)			73
Azerbaijan	Various (BP-operated)	**203**	158	140
Western Indonesia	Sanga-Sanga	**55**	59	59
India[b]	D1 D3	**117**	253	121
	D26	**38**	59	25
	Other	**1**	1	
Total India		**156**	313	146
Vietnam[b]	Various (BP-operated)			69
China[b]	Yacheng	**34**	54	70
Oman		**22**	14	20
Sharjah	Various (BP-operated)	**25**	35	41
Total Rest of Asia		**494**	633	618
Total Asia		**494**	633	618

BP s net production by major field natural gas continued

	Field or area	million cubic feet per day BP net share of production[a] 2013	2012	2011
Subsidiaries				
Australia	Perseus/Athena	**139**	141	170
	Goodwyn	**57**	73	72
	Angel	**89**	110	126
	Other	**146**	111	87
Total Australia		**431**	435	455
Eastern Indonesia	Tangguh (BP-operated)	**349**	352	340
Total Australasia		**780**	787	795
Total subsidiaries[c]		**5,845**	6,193	6,393
Equity-accounted entities (BP share)				
TNK-BP (Russia, Venezuela, Vietnam)[b d]	Various	**184**	785	710
Rosneft (Russia, Canada, Venezuela, Vietnam)[b e]	Various	**617**		
Angola	ALNG	**8**		
Argentina	Various	**329**	355	371
Bolivia	Various	**55**	34	14
Venezuela[b]	Various			4
Western Indonesia	Various	**22**	26	26
Total equity-accounted entities[c]		**1,216**	1,200	1,125
Total subsidiaries and equity-accounted entities		**7,060**	7,393	7,518

[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 2013, BP divested its interests in TNK-BP, its interests in the Harding, Devenick, Maclure, Braes, Braemar and Sean fields in the North Sea, its interests in the US onshore Moxa upstream operation in Wyoming and its interests in the Yacheng gas field in the South China Sea. It also acquired an interest in Rosneft. In 2012, BP divested its interests in the US Hugoton basin including the Jayhawk NGL plant, its interests in the Gulf of Mexico Marlin, Dorado, King, Horn Mountain, Holstein, Ram Powell and Diana Hoover assets, a portion of its interest in the 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 operation with Reliance, in the Eagle Ford shale in North America and additional volumes in the Gulf of Mexico. BP divested its holdings in Pompano along with other interests in the 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.

[c] 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.

[d] Estimated production for 2013 represents BP s share of TNK-BP s estimated production from 1 January to 20 March, averaged over the full year.

[e] 2013 reflects production for the period 21 March to 31 December, averaged over the full year.

Because of rounding, some totals may not agree exactly with the sum of their component parts.

Table of Contents

The following tables provide additional data and disclosures in relation to our oil and gas operations.

Average sales price per unit of production[a]

$ per unit of production

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia[b]	Rest of Asia		
Subsidiaries										
2013										
Liquids[c]	**105.86**	**102.72**	**91.88**		**87.16**	**104.27**		**108.24**	**100.41**	**99.24**
Gas	**9.43**	**10.18**	**3.07**		**4.66**	**5.75**		**4.99**	**10.55**	**5.35**
2012										
Liquids[c]	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[c]	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
Equity-accounted entities[d]										
2013										
Liquids[c]					**75.45**		**95.28**	**11.58**		**63.65**
Gas					**4.05**		**2.47**	**13.21**		**3.26**
2012										
Liquids[c]					79.08		83.85	10.15		69.41
Gas					2.35		2.35	5.08		2.52
2011										
Liquids[c]					73.51		84.39	8.11		71.35
Gas					2.31		2.23	12.21		2.40

[a] Units of production are barrels for liquids and thousands of cubic feet for gas. Realizations include transfers between businesses.

[b] Amounts reported for Russia in 2013 include BP s share of Rosneft s worldwide activities, including insignificant amounts outside Russia.

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

[d] 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[a]

$ per unit of production

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia[b]	Rest of Asia		
Subsidiaries										
2013	**34.10**	**24.48**	**16.11**		**5.92**	**13.84**		**13.20**	**3.21**	**13.16**
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
Equity-accounted entities										
2013					**12.16**					