BP PLC
Form 20-F
March 03, 2015
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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 2014

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 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 2017	New York Stock Exchange
Floating Rate Guaranteed Notes due February 2018	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
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**
1.846% Guaranteed Notes due 2017	**New York Stock Exchange**
1.375% Guaranteed Notes due 2018	**New York Stock Exchange**
1.674% Guaranteed Notes due 2018	**New York Stock Exchange**
2.241% Guaranteed Notes due 2018	**New York Stock Exchange**
4.750% Guaranteed Notes due 2019	**New York Stock Exchange**
2.237% Guaranteed Notes due 2019	**New York Stock Exchange**
2.315% Guaranteed Notes due 2020	**New York Stock Exchange**
2.521% Guaranteed Notes due 2020	**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**
3.535% Guaranteed Notes due 2024	**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

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	20,005,961,293
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:

U.S. GAAP ¨ International Financial Reporting Standards as issued by the 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

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Annual Report and

Form 20-F 2014

bp.com/annualreport

Building a stronger,

safer BP

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Who we are

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

Through our work we provide customers with fuel for transportation, energy for heat and light, lubricants to keep engines moving and the petrochemicals products used to make everyday items as diverse as paints, clothes and packaging. Our projects and operations help to generate employment, investment and tax revenues in countries and communities across the world. We employ around 85,000 people.

As a global group, our interests and activities are held or operated through subsidiaries, branches, joint arrangements or associates established in and subject to the laws and regulations of many different jurisdictions. The UK is a centre for trading, legal, finance, research and technology and other business functions. We have well-established operations in Europe, North and South America, Australasia, Asia and Africa.

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

BP proposition

We prioritize value over volume by actively managing a high-value upstream and downstream portfolio and investing only where we can apply the distinctive strengths, capabilities and technologies that we have built up over decades.

Our objective is to create shareholder value by growing sustainable free cash flow over the long term. Our disciplined approach enables us to grow distributions to our shareholders over time.

See *bp.com/bpproposition*

| Your feedback

Front cover imagery

An operations technician and process engineer perform safety checks on the Atlantis platform in the Gulf of Mexico. The region is an important part of our upstream portfolio and Atlantis is one of four BP-operated platforms there. The Mardi Gras pipeline that stretches across 450 miles of the Gulf moves oil and gas production to onshore facilities from these platforms.

We welcome your comments and feedback on our reporting. Your views are important to us and help us shape our reporting for future years.

You can provide this at *bp.com/annualreportfeedback* or by emailing the corporate reporting team. Details are on the back cover.

BP Annual Report and Form 20-F 2014

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BP in 2014

We have reshaped and repositioned the business for the future, with a clear strategy that has put us on course to grow value for shareholders.

« Glossary

Words with this symbol« are defined in the glossary on page 252.

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Information about this report

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 2014. A cross reference to Form 20-F requirements is included on page 257.

This document contains the Strategic report on pages 1-50 and the inside cover (Who we are section) and the Directors report on pages 51-71, 90, 167-196 and 207-255. 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 72-88. The consolidated financial statements of the group are on pages 89-166 and the corresponding reports of the auditor are on pages 94-95.

BP Annual Report and Form 20-F 2014 and *BP Strategic Report 2014* (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 2014* or *BP Strategic Report 2014* (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 *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 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 244 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 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.

Registered office and our worldwide headquarters:

BP p.l.c.

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London SW1Y 4PD

UK

Tel +44 (0)20 7496 4000

Our agent in the US:

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Houston, Texas 77079

US

Tel +1 281 366 2000

Registered in England and Wales
No. 102498.

London Stock Exchange symbol
BP.

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BP at a glance

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BP around the world

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« Defined on page 252.

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,

We started 2014 with confidence in the overall development of the world and a feeling of progress in most of the world s economies after several challenging years. However, the year ended with significant uncertainties. BP operates in a geopolitical environment that has become more turbulent and the price of oil has significantly declined, returning to a pattern of volatility not seen for several years. The industry must adapt rapidly. Even before the recent volatility, we have taken measures to streamline and reshape BP. We believe we are well positioned to meet the challenges of the coming years.

In 2011, we set out our 10-point plan with clear goals that we have delivered over the last three years. This is a significant achievement for Bob Dudley and his team. It marks a major step in refocusing the company after the tragic events of 2010 when 11 people lost their lives in the Deepwater Horizon accident something we must never forget. Our strategic progress has to be tempered by the finding of gross negligence in the Clean Water Act litigation in the US, which we strongly disagree with and are appealing.

Strategy

Completing the 10-point plan does not mean that our work is done. Far from it. The board continues to be deeply involved in discussing and shaping our strategy with its clear priorities, quality portfolio and distinctive capabilities.

We successfully sold assets at a time of higher oil prices and are now going through a rapid cost adjustment to address this new landscape and improve our underlying business performance. We are refocusing our approach to producing hydrocarbons in the US Lower 48 and we are resetting our operations across the entire business. This is all taking place without compromising on safety. Our recent strategic partnership with Chevron in the Gulf of Mexico demonstrates what we mean by value over volume through a new ownership and operating model. Our goals are to make investment choices that play to our strengths, increase sustainable free cash flow and grow our distributions to shareholders.

We began a number of these initiatives earlier in 2014, putting us ahead of the current oil price pressures. These strategic actions will continue and more will be necessary as we respond to short-term imperatives. We aim to ensure that BP builds on its distinctive strengths in 2015 and beyond.

Shareholder distributions

The improved performance over the year and progress in strategic delivery has led to the board s decision to increase the dividend. During 2014, the board reviewed the dividend twice and each time raised it by 2.6% . These increases are part of our strategy to grow distributions. During 2014 BP completed its $8-billion share buyback programme using proceeds from the sale of our interest in TNK-BP. Shares worth a further $2.3 billion were also bought back in the year. In the present environment, returns to shareholders remain a key priority.

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Board performance

For information about the board and its committees see page 51.

Remuneration

For information about our directors remuneration see page 72.

Oversight

The board has continued to maintain oversight of performance, risk and financial efficiency and kept a constant scrutiny on safety. Each year we review and monitor the group level risks through our own work and our committees, who carry out the majority of the work, leaving the board free to address strategic issues.

There are, however, longer-term issues on which we also have to focus, such as carbon and its role in climate change. It is clear that it is for governments and regulators to set the boundary conditions to address these issues and we will develop our business within their framework. For example, we already factor a price for carbon into our project evaluation. We recognize that we need to play our part in informing this debate and we do this through our projections for future world energy markets in the *BP Energy Outlook 2035*. Throughout, we must remain alert to developments that may alter the world in which we operate. The board is recommending that shareholders support the resolution at the annual general meeting seeking greater transparency of reporting in this important area.

Governance and succession

The board regularly considers how it operates and the appropriate composition and mix around the board table both to respond to today s challenges and BP s future strategic direction. Antony Burgmans, the current chair of the remuneration committee, will stand down as a director in 2016. In anticipation of his departure, Dame Ann Dowling will take over the chair of that committee during 2015. We have also considered the chairs and membership of all other committees. In 2012, upon Andrew Shilston joining the board and being appointed the senior independent director, we announced that Antony Burgmans would retain a role as an internal sounding board. This role will cease after the annual general meeting. Andrew will join the remuneration and nomination committees.

I would like to welcome Alan Boeckmann who joined the board as a non-executive director in July. Alan brings deep experience of contractor management, procurement and project delivery in our industry following his career in Fluor Corporation. Alan will be joining the remuneration committee after the annual general meeting. Our longest serving director, Iain Conn, left the company in December to become chief executive of Centrica after an almost 30-year career with BP, spanning different businesses and regions. George David will retire from the board at our AGM in April. My fellow directors and I thank both Iain and George for their huge contributions and work on behalf of the board.

I would also like to thank Bob Dudley, his team, my board colleagues and all our employees for all that they have done. Finally, my thanks go to you, our shareholders, for the support you have shown us during the year.

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Top: Members of BP s safety, ethics and environmental assurance committee (SEEAC) in Azerbaijan.

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Bottom: Cynthia Carroll attends a briefing during a visit to Brazil with SEEAC.

Carl-Henric Svanberg

Chairman

3 March 2015

Group chief executive s letter

94.9%

2014 refining availability.

90%

Upstream BP-operated plant efficiency«.

Dear fellow shareholder,

The year 2014 was pivotal for BP. Despite the increasingly challenging business environment, we completed the 10-point plan we had set out in 2011 to make BP a safer, stronger, better performing business. Compared with three years ago, we have reduced safety-related incidents, delivered strong operating efficiencies and met our target to increase operating cash flow by more than 50%.

Our performance is important, not only because we achieved our targets, but because we did what we said we would do. I know how important it is to shareholders that we continue delivering on our commitments.

2014 was a turbulent year for BP and the industry. Oil prices fell dramatically and returned to their familiar pattern of volatility, after several exceptional years in which they remained above $100 per barrel. I expect these lower and more volatile prices to continue through 2015 and likely longer. We are now resetting the business to deliver value in this new context, scaling back capital spending and reducing costs, while always maintaining our primary focus on safety.

Our efforts over the past three years have helped prepare us to face the new oil price challenge with resilience. We have reshaped and strengthened our portfolio through a divestment programme, reduced our costs to reflect a smaller footprint and articulated a strategy based on clear priorities, a quality portfolio and distinctive capabilities.

Clear priorities

Safe and reliable operations will always be our first priority. While we have made real progress in the past three years, sadly there were three workforce fatalities in 2014, in accidents at a German refinery, a UK North Sea platform and an Indonesian petrochemicals plant. Our thoughts are with the families and friends of those who died and we will implement the lessons from these tragic events.

Since 2011 we have reduced the number of tier 1 and tier 2 process safety events the most serious incidents, leaks, spills and other releases. After making very good progress in 2013, we saw a higher number of such incidents in 2014. We are renewing our efforts to ensure conformance with our operating management system, allied to the right personal behaviours, taking great care in everything we do.

We clearly demonstrated capital discipline through 2014, restricting spending to around $23 billion, relative to guidance of $24-25 billion. We also saw good project execution as we met our plans to bring onstream seven start-up projects.

Quality portfolio

We continue to actively manage our portfolio, focusing on assets which play to our strengths and divesting assets that no longer fit our strategy. In both our Upstream and Downstream businesses, we are taking a rigorous approach to capital allocation and concentrating on efficiency and competitiveness in our activities. Making the right investment choices is of the highest priority.

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Delivery of our 10-point plan

For details of our performance against the plan see page 21.

Our strategy

For more on our strategic priorities and longer-term objectives see page 13.

Our key performance indicators

Find out how we measure our performance on page 18.

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Top: Bob Dudley at the World Petroleum Congress in Moscow.

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Bottom: Bob Dudley congratulates winners at the Helios awards where teams from across the world are recognized for their contributions to building a safer, stronger BP in line with our values.

We grew our exploration position during the year, with new access in five areas and hydrocarbon discoveries in the Gulf of Mexico, Brazil, the North Sea, Egypt and Angola. We began operating our onshore oil and gas operations in the Lower 48 states of the US as a separate business in January 2015. In the Downstream, we improved performance from fuels marketing, increased our capacity to refine heavy crude and shale oil in the US, maintained the focus on premium brands and growth markets in lubricants and reviewed the petrochemicals business to increase its earnings potential.

Having completed our $38-billion divestment programme ahead of schedule, we committed to make a further $10 billion of divestments by the end of 2015. By the end of 2014 we had agreed transactions amounting to $4.7 billion.

Distinctive capabilities

BP s distinctive capabilities of advanced technology, proven expertise and strong relationships underpin our progress. We have invested over the years to be a specialist in several key areas of technology. For example, in 2014 we started using robots to test enhanced oil recovery options, helping us reduce time to production.

The expertise of our people is central to our progress so developing our employees in critical areas is an ongoing activity. For example, we run specialist academies dedicated to global wells expertise and safety and operational risk, as well as other areas.

Strong relationships remain vital with communities, governments, partners, suppliers, staff and shareholders. The rapid progress made on the Southern Corridor project, which will pipe natural gas from the Caspian Sea to markets as far away as Italy, is just one example. With our partners, we have already awarded more than $9 billion of contracts to make, transport and install facilities.

A challenging environment

In 2015 we entered a very different landscape from that in which we began last year. The lower oil price presents formidable challenges for the industry. In these volatile times, BP continues to drive capital discipline by constraining the total level of capital spend in any one year, taking account of the opportunities available and the flexibility of our balance sheet.

Meanwhile, we continue to manage issues specific to BP. The legal proceedings in the US associated with the Deepwater Horizon accident and oil spill continue. In the first trial phase the judge issued a finding of gross negligence and wilful misconduct. We strongly disagree with these findings and have appealed. In the second phase the court found no gross negligence in our source control efforts and ruled that 3.19 million barrels of oil were discharged into the Gulf of Mexico. We have also appealed this ruling. The penalty phase trial finished in February, with the ruling to come at a later date. In all of the proceedings, we are seeking fair and just outcomes while protecting the best interests of our shareholders.

Our investment in Rosneft, funded from the proceeds of our sale of TNK-BP in 2013, continues to attract attention. Our approach is to comply with all relevant sanctions and otherwise to maintain our distinctive, long-term investment and relationship with Rosneft in a country that holds some of the world s largest oil and gas resources. There is strong interdependence between Russia and its trading partners, and I believe that over time such commercial links tend to ease tensions rather than exacerbate them.

The BP of 2015 is a robust and resilient business, a global team that has been through some of the most difficult times an organization can face and emerged stronger, safer and better than before.

Bob Dudley

Group chief executive

3 March 2015

« Defined on page 252.

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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 markets in 2014

See page 20 for information on oil and gas prices in 2014.

How BP is preparing for the near-term outlook

We exercise capital discipline by constraining the total level of capital spend and the number of projects sanctioned each year.

We sanction upstream projects at $80[a] per barrel, while testing projects for resilience at $60[a] per barrel.

Our balance sheet gives us resilience to withstand a period of low prices.

With a third of our production from production-sharing agreements and an increasing portfolio of high-quality gas projects, we are reducing our vulnerability to global oil price movements.

Near-term outlook

Oil prices, after around four years of averaging around $100 per barrel, have fallen by more than 50%. This reflects strong production growth in the US, increases in global supply elsewhere and weaker global demand. Prices weakened further following OPEC s decision in November to maintain production.

Prices are expected to remain low through the near term, at least. And while we anticipate supply chain deflation by 2016 and beyond, as industry costs follow oil prices with a lag, this will be a tough period of intense change for the industry as it adapts to this new reality.

Long-term outlook

Population and economic growth are the main drivers of global energy demand. The world s population is projected to increase by 1.6 billion from 2013 to 2035,

Affordability fossil fuels can become more difficult to access as the easiest and highest quality resources are depleted first, and many non-fossil fuel resources remain costly to produce at scale.

Continued advances in technology and energy-industry productivity are required to deliver affordable, sustainable and secure energy. The shale gas revolution demonstrates the potential impact of such developments.

Effective policy

We believe governments must set a stable framework to encourage private sector investment and to help consumers choose wisely. This includes secure access for the exploration and development of energy resources; mutual benefits for resource owners and development partners; and an appropriate legal and regulatory environment with an economy-wide price on carbon.

We continue to right-size the group s cost base to align with BP s smaller footprint.

[a] In real terms based to 2012.

For further detail on the projections of future energy trends contained in this section, please refer to *BP Energy Outlook 2035*.

and the world economy is likely to more than double in size over the same period. Improvements to energy efficiency, further stimulated by new climate policies and a shift towards less energy-intensive activities in fast-growing economies will restrain the growth of energy consumption. But we still expect world demand for energy to increase by as much as 37% between 2013 and 2035, with 96% of the growth in non-OECD countries.

Energy resources are available to meet this growing demand, but developing these resources presents a number of challenges:

Sustainability action is needed to limit carbon dioxide (CO_2) and other greenhouse gases emitted through fossil fuel use.

Supply security more than 60% of the world s known reserves of natural gas are in just five countries, and more than 80% of global oil reserves are located in nine countries, often distant from the hubs of energy consumption.

Energy efficiency

Greater efficiency helps with affordability because less energy is needed; with security because it reduces dependence on imports; and with sustainability because it reduces emissions. Innovation can play a key role in improving technology, bringing down cost and increasing efficiency. In transport, for example, we believe energy-efficient technologies and biofuels could offer the most cost-effective pathway to a secure, lower-carbon future.

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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.*

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[a]), oil and gas would still make up 49% of the energy mix in 2030 and 43% in 2040.

We expect oil to remain the dominant source for transport fuels, accounting for almost 90% of demand in 2035.

Natural gas, in particular, is likely to play an increasing role in meeting global energy demand. By 2035 gas is expected to provide 26% of global energy, matching the share of coal. Natural gas produces about half as much CO_2 as coal per unit of power generated, so increasing the share of gas versus coal helps to restrain greenhouse gas emissions. Shale gas has already had a significant impact

Renewables

Renewables will play an increasingly important role in addressing the long-term challenges of energy security and climate change. They are already the fastest-growing energy source, but are starting from a low base. By 2035, we estimate renewable energy, excluding large-scale hydroelectricity, is likely to meet around 8% of total global energy demand.

Temporary policy support is needed to help commercialize lower-carbon options and technologies, but they will ultimately need to become commercially self-sustaining, supported only by a carbon price.

Beyond 2035

We expect that growing population and per capita incomes will continue to drive growing demand for energy. These dynamics will be shaped by future technology developments, changes in tastes, and future policy choices all of which are inherently uncertain. Concerns about energy security, affordability and environmental impacts are all likely to be important considerations. These factors may accelerate the trend towards more diverse sources of energy supply, a lower average carbon footprint, increased efficiency and demand on US gas prices and demand, and is expected to contribute 47% of the growth in global natural gas supplies between 2013 and 2035.

New sources of hydrocarbons may be 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.

management.

[a] From World Energy Outlook 2014. © OECD/International Energy Agency 2014, page 607. The IEA s 450 policy scenario assumes governments adopt commitments to limit the long-term concentration of greenhouse gases in the atmosphere to 450 parts-per-million of CO_2 equivalent.

Our strategy

Find out how BP can help meet energy demand for years to come on page 13.

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. Also available in Excel and video format.

See *bp.com/energyoutlook*

We provide a long-term technology view on future trends and their potential impact on the energy system. This helps assess lessons learned from technology s evolution and how it may shape our future energy choices.

See *bp.com/energy-technology-future*

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Our business model

We aim to create value for our investors and benefits for the communities and societies where we operate.

A process engineer monitors instrument readings at our Castellón refinery in Spain. The refinery has the flexibility to run sour, heavy and highly acidic crudes.

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In Trinidad & Tobago we are the largest hydrocarbon producer, accounting for about 50% of the nation s oil and gas.

We believe 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. By supplying energy, we support economic development and help to improve quality of life for millions of people. Our activities also generate jobs, investment, infrastructure and revenues for governments and local communities.

Our business model spans everything from exploration to marketing. We have a diverse integrated portfolio that is focused and adaptable to prevailing conditions. 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.

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

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 where 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.

Illustrated business model

For an at a glance overview of our business model see page 2.

Our businesses

For more information on our upstream and downstream business models, see pages 24 and 29 respectively.

Finding oil and gas g	Developing and extracting g	Transporting and trading g	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 aim to create value by progressing 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 rail. Using our trading and supply skills and knowledge, we buy and sell at each stage of 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.

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Our strategy

Our goal is to be a focused oil and gas company that delivers value over volume.

An operator commissions a steam system at the Whiting refinery in the US.

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Technical operations onboard our floating production, storage and offloading vessel in Angola.

We prioritize **value over volume** by actively managing a high-value upstream and downstream portfolio and investing only where we can apply the distinctive strengths, capabilities and technologies we have built up over decades.

Our objective is to create shareholder value by growing **sustainable free cash flow«** over the long term. Our disciplined approach enables us to **grow distributions** to our shareholders over time.

We are pursuing our strategy by setting clear priorities, actively managing a quality portfolio and employing our distinctive capabilities.

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

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 work to develop and maintain strong relationships with governments, partners, civil society and others to enhance our operations in almost 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 how we are delivering our strategy on page 14.

Our key performance indicators

See how we measure our progress on page 18.

projects efficiently so they are on time and on budget. And we aim to make disciplined financial choices in support of growth in operating cash« from our businesses, disciplined allocation of capital and financial resilience.

Risks

Find out how we manage the risks to our strategy on page 46.

Quality portfolio

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 deep water, giant fields and selected gas value chains. And, in our downstream businesses, we plan to leverage our newly upgraded assets, customer relationships and technology to grow operating cash flow.

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

« Defined on page 252.

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Our strategy in action

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How we deliver	How we measure	Strategy in action in 2014	
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.	**Running reliably** Running operations safely is Air BP s first priority. See page 40.	**28** tier 1 process safety events.
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, total shareholder return, underlying replacement cost profit per ordinary share.	**Increasing value** An alternative solution to increase long-term value. See page 21.	**$32.8bn** 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.	**Unlocking hidden resources** Using our advanced technology and exploration experience to access gas in Oman. See page 27.	**7** major project start-ups in Upstream.
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.	**Extending the life of the North Sea** Our latest discovery demonstrates the basin s ongoing potential. See page 28.	**63%** reserves replacement ratio.[a]
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	Production.	**Committing to the future** Increasing production in the	**3.2** million barrels of oil equivalent per day.[a]

momentum for years to come.

Gulf of Mexico.

See page 25.

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.

Driving success

Our retail partnership with Marks & Spencer is driving sales growth.

See page 31.

94.9%

refining availability.

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, recovery, efficiency and products.

Strong relationships
We aim to form enduring partnerships in the countries in which we operate, building strong relationships with governments, customers, partners, suppliers and communities to create mutual advantage. Co-operation helps unlock resources found in challenging locations and transforms them into products for our customers.

Proven expertise
Our talented people help to drive our business forward. They apply their diverse skills and expertise to deliver complex projects across all areas of our business.

[a] On a combined basis of subsidiaries« and equity-accounted entities.

« Defined on page 252.

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Our distinctive capabilities

We use technology to find and produce more oil and gas, improve our processes for conversion into valuable products and develop lower-carbon energy solutions.

We aim to build strategic relationships with universities for research, recruitment, policy insights and education. Our long-term research programmes around the world are exploring areas from reservoir fluid flow to novel lubricant additives. For example through the BP International Centre for Advanced Materials almost 70 researchers are working on around 20 projects to advance the understanding and use of materials across a variety of energy and industrial applications.

The first priority for all our technology teams is improving the safety and integrity of our operations.

Our upstream technology programmes 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 improving the efficiency of unconventional oil and gas production.

We focus our downstream technology programmes on improving the performance of our refineries and petrochemicals plants and on creating high quality, energy efficient, cleaner products.

We employ scientists and technologists at seven major technology centres in the US, UK and Germany. In 2014 we invested $663 million in research and development (2013 $707 million, 2012 $674 million).

See bp.com/technology

At our Wayne technology center in New Jersey chemists research new formulations to improve lubricant

Seismic imaging

We use our imaging expertise to increase the productivity and quality of the data we capture on land and offshore. We conducted one of our largest-ever onshore seismic surveys

Enhanced oil recovery (EOR)

BP delivers more light oil EOR production than any other international oil company. In 2014 we introduced the world s first automated robot for testing EOR performance.

in 2014 covering 2,800km^2 at the Khazzan field in Oman.

technologies, shortening the time we need to spend on development and trials before bringing them to field.

Production optimization

Our *Field of the Future* technologies provide real-time information to help manage operational risk, improve plant equipment reliability and optimize production. In 2014 we established a digital centre of expertise for technologies to analyse data, improve decision making and enhance efficiency.

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.

We aim to maintain a skilled workforce to deliver our strategy and meet our commitments to investors, partners and the wider world. We compete for the best people within the energy sector and other industries.

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.

We have a bias towards building capability within the organization, complemented by selective external recruitment where necessary, and invest in all our employees development to build a sustainable talent pipeline.

Our approach to professional development and training helps build individual capabilities, reducing a potential skills gap. We believe our shared values help everyone at BP to contribute to their full potential.

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Corrosion prevention

Wireless Permasense® systems provide frequent and on-demand corrosion monitoring by detecting unexpected changes in the wall thickness of pipes. Developed in collaboration with Imperial College, London, they are used across all our refineries to monitor the integrity of critical assets.

Fuels

Our gasoline and diesel additive Ultimate in a Bottle, launched in China in 2014, helps clean and protect engines, enhance performance for diesel in cold weather and reduce emissions to improve air quality.

Biofuels

We are developing biobutanol in conjunction with DuPont. This second-generation biofuel can be blended into gasoline in greater proportions and is more compatible than ethanol with the infrastructure used for existing fuel supplies.

Lubricants

We focus on providing energy-efficient and high-performance products to customers. In 2014 we launched *Castrol EDGE* with *Titanium Fluid Strength Technology*, which changes the way engine oil behaves under extreme pressure, reducing friction by up to 15%.

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.

We work closely with governments, national oil companies and other resource holders to build long-lasting relationships that are crucial to the success of our business.

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

We place enormous importance on acting responsibly and meeting our obligations as we know from experience that trust can be lost. We work on big and complex projects with partners ranging from other oil companies to suppliers and contractors. Our activity creates value that benefits governments, customers, local communities and other partners.

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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 periodically review our metrics and test their relevance to our strategy. We believe non-financial measures such as safety and an engaged and diverse workforce have a useful role to play as leading indicators of future performance.

Changes to KPIs

We have replaced the RC profit per ordinary share KPI to underlying RC profit per ordinary share. This is one of the measures used by management to evaluate BP s operational performance and is also used as a performance measure for executive directors remuneration. All other KPIs remain the same.

Remuneration

To help align the focus of our board and executive management with the interests of our shareholders, certain

Underlying RC profit«

per ordinary share (cents)

Underlying RC profit is a useful measure for investors because it is one of the profitability measures BP management uses to assess performance. It assists management in understanding the underlying trends in operational performance on a comparable year-on-year basis.

It reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses« from profit or loss. Adjustments are also made for non-operating items« and fair value accounting effects«. The IFRS equivalent can be found on page 208.

2014 performance The decrease in underlying RC profit per ordinary share for the year compared with 2013 was mainly due to a

Operating cash flow« ($ billion)

Operating cash flow is net cash flow provided by operating activities, as reported in 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.

2014 performance
Operating cash flow in 2014 was higher in line with delivery of the 10-point plan.

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. For the nearest equivalent measure on an IFRS basis and for further information see Financial statements Note 25.

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.

Directors remuneration

See how our performance impacted 2014 pay on page 72.

Key

KPIs used to measure progress against our strategy.

KPIs used to determine 2014 and 2015 remuneration.

lower profit in Upstream and lower earnings from Rosneft.

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 downtime.

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

2014 performance
Refining availability decreased by 0.4% from 2013 to 94.9% reflecting the completion of the Whiting refinery modernization project and ramp-up of operations.

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.

2014 performance Our workforce RIF, which includes employees and contractors combined, is 0.31, level with 2013. While this is encouraging, we have seen an increase in our day away from work case frequency (see page 39). We are reviewing our personal safety programmes and continue to focus our efforts on safety.

2014 performance
Gearing at the end of 2014 was 16.7%, up 0.5% on 2013 and within our target band of 10-20%.

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.

2014 performance The increase in 2014 reporting reflects the introduction of enhanced automated monitoring for many remote sites in our Lower 48 business. Using a like-for-like approach with previous years reporting, our 2014 loss of primary containment figure is 246.

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 reinvested to purchase additional shares at the closing price on the ex-dividend date. We are committed to maintaining a progressive and sustainable dividend policy.

2014 performance TSR decreased during the year, primarily as a result of a fall in the BP share price, partly offset by two dividend per share increases in 2014.

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.

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

2014 performance The reserves replacement ratio reflects lower reserves bookings as a result of fewer final investment decisions in 2014 and revisions of previous estimates.

Major project delivery

Major projects are defined as those with a BP net investment of at least $250 million, or considered to be of strategic importance to BP, or of a high degree of complexity.

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.

2014 performance In total we delivered seven major project start-ups in Upstream.

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.

2014 performance BP s total reported production including our Upstream segment and Rosneft was 2.4% lower than in 2013. This reduction reflected the Abu Dhabi onshore concession expiry and divestments, partially offset by increased production from higher-margin areas and higher production in Rosneft in 2014 compared to the aggregate production in Rosneft and TNK-BP in 2013.

Tier 1 process safety events«[a]

Greenhouse gas emissions[b]

Group priorities engagement[e] (%)

Diversity and inclusion[e] (%)

(million tonnes of CO_2 equivalent)

We report tier 1 process safety events, 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.

2014 performance The number of tier 1 process safety events has decreased substantially since 2010. We take a long-term view on process safety indicators because the full benefit of the decisions and actions in this area is not always immediate.

[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.

We provide data on greenhouse gas (GHG) emissions material to our business on a carbon dioxide-equivalent basis. This includes CO_2 and methane for direct emissions.[c] Our GHG KPI 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.[d] Emissions data for Rosneft can be found on its website.

2014 performance The decrease in our GHG emissions is primarily due to the sale of our Carson and Texas City refineries in the US as part of our divestment programme.

[b] The reported 2013 figure of 49.2MteCO_2 e has been amended to 50.3MteCO_2 e.

[c] For indirect emissions data see page 42.

[d] For our emissions on an operational control basis see page 42.

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

2014 performance The 2014 survey found that employees remain clear about safety procedures, standards and requirements that apply to them and that pride in working at BP has increased steadily since 2011. Understanding and support of BP s strategy is strong at senior levels, but needs further communication and engagement across the organization.

[e] Relates to BP employees.

Each year we report the percentage of women and individuals from countries other than the UK and the US among BP s group leaders. This helps us track progress in building a diverse and well-balanced leadership team.

2014 performance The percentage of our group leaders who are women or non-UK/US has remained steady this year. We remain committed to our aim that women will represent at least 25% of our group leaders by 2020.

« Defined on page 252.

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Our markets in 2014

A snapshot of the global energy market in 2014, as oil prices

return to a pattern of volatility.

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A mechanical technician works on the floating, production, storage and offloading vessel in Angola s ultra-deep water.

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Pipe alley at Cooper River petrochemicals plant. The site is one of the world s largest producers of PTA, a raw material primarily used to manufacture polyester and plastic bottles.

Crude oil prices (quarterly average)

Oil and gas pricing

For more on upstream markets in

2014 see page 25.

Refining margins

Economic growth has remained relatively weak globally, and was weaker in the emerging non-OECD economies than recent years. Within the OECD, the US and UK performed best growing at around their medium-term potential while Japan and the Eurozone have underperformed against their potential.

Oil

Crude oil prices, as demonstrated by the industry benchmark of dated Brent, averaged $98.95 per barrel in 2014. For the period from 2010 to mid-2014, oil prices followed a pattern of relative stability at around $110 a barrel. Prices averaged $109 during the first half of 2014, but fell sharply by more than 50% since June in the face of continued strong growth of light, sweet oil production in the US, and weak global consumption growth. Brent prices ended the year near $55.

Amid continued high oil prices for much of the year and weak economic growth in emerging economies, global oil consumption

Natural gas

Global price differentials in 2014 continued to narrow. US gas prices moved up, while European and Asian spot LNG prices weakened. The Henry Hub index increased from $3.7 per million British thermal units (mmBtu) in 2013 to $4.4 in 2014.

Spot LNG prices in Europe and Asia fell with rising global LNG supplies and weak demand growth. New LNG projects in Papua New Guinea and Australia, and recovering supplies in Africa have added to the market in 2014.

Moderating demand and milder weather reduced the UK National Balancing Point hub price to an average of 50 pence per therm in 2014 (2013 68). The Japanese spot price fell to an average of $13.9/mmBtu in 2014 (2013 $16.6).

In 2013 growth in natural gas consumption slowed to a below-average rate and broad

For more on downstream markets in

2014 see page 30.

increased by a below-average 0.6 million barrels per day (mmb/d) for the year (0.7%).[a] The growth in consumption was greatly exceeded by record growth in non-OPEC production (2.0 mmb/d), mainly by continued strong growth in US output. OPEC crude oil production fell slightly due to renewed outages in Libya. On balance, production significantly exceeded consumption, resulting in a large increase in OECD commercial oil inventories.

In 2013 global oil consumption grew by roughly 1.4 million barrels per day (1.4%), significantly more than the increase in global production (0.6%).[b] Non-OPEC production accounted for all of the net global increase, driven by robust US growth.

[a] From Oil Market Report 10 February 2015©, OECD/IEA 2015, page 4.

[b] *BP Statistical Review of World Energy June 2014*.

differentials between regional gas prices continued, although they did not widen further as US gas prices recovered from their 2012 lows. Global LNG supply expanded in 2013, following a contraction in supply in 2012. But the LNG market remained tight, as strong demand continued in Asia from economic growth and nuclear power outages, and in Latin America due to the effect of a drought on hydroelectric production.

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Group performance

A summary of our group financial and operating performance.

10-point plan performance

In 2014 we completed our three-year 10-point plan, established in 2011, to help stabilize BP and restore trust and value in response to the tragic Deepwater Horizon accident in 2010. Here we report on our performance in delivering the plan over the period.

Relentless focus on safety
We reduced tier 1 process safety events« and loss of primary containment (LOPC) by 62% and 21% respectively over the plan period. However, in 2014 there were eight more tier 1 events and 25 more LOPC incidents than 2013. Safety remains our primary focus and we continue to focus our efforts on it.

Play to our strengths
We accessed almost 158,000 km^2 exploration acres, made 13 new discoveries and drilled a total of 44 exploration wells (2014 18).

Stronger and more focused
We have reshaped our portfolio to have a set of high-value deepwater assets, gas value chains, giant fields, and a high-quality downstream business. We sold around half of our upstream installations and pipelines, and one third of our wells while retaining roughly 90% of our proved reserves and production.

Simpler and more standardized
We implemented standardized global systems and processes and established global functional organizations to conduct all BP-operated drilling and wells activity and manage the development of our major projects«.

More visibility and transparency to value
We provide downstream results by fuels, petrochemicals and lubricants, and report earnings from Rosneft as a separate operating segment.

Active portfolio management
We completed our $38-billion divestment programme ahead of schedule and plan for a further $10 billion of divestments before the end of 2015, with $4.7 billion of sales already agreed.

New upstream projects onstream with unit cash margins« double the 2011 average
We started up 15 major upstream projects, of which 13 are in the four higher-margin areas (Angola, Azerbaijan, Gulf of Mexico and North Sea). Average forecast unit cash margins (2014-23) for the 15 projects at $100/bbl oil price were more than double the 2011 upstream segment average.

Generate around 50% more in operating cash flow« by 2014 versus 2011[a]
We reported $32.8 billion of operating cash flow in 2014 (averaged oil price of $98.95/bbl, averaged Henry Hub gas price of $4.43/mmBtu) exceeding our target of around 50% increase on 2011.

Half of incremental operating cash for reinvestment half for other purposes including distributions

The dividend paid in 2014 increased by 39% since 2011, and we carried out $10.3 billion of share buybacks since March 2013, when a share repurchase programme was announced.

Strong balance sheet

Our gearing« stayed within our target range of 10-20%, decreasing from 20.4% in 2011 to 16.7% at the end of 2014.

[a] Assumed an oil price of $100/bbl and a Henry Hub gas price of $5/mmBtu in 2014. 2011 excluded BP s share of TNK-BP dividends; 2014 included BP s share of Rosneft dividends. The projection included 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.

« Defined on page 252.

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Financial and operating performance

			$ million
	2014	2013	2012
Profit before interest and taxation	**6,412**	31,769	19,769
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(1,462)**	(1,548)	(1,638)
Taxation	**(947)**	(6,463)	(6,880)
Non-controlling interests	**(223)**	(307)	(234)
Profit for the year[a]	**3,780**	23,451	11,017
Inventory holding (gains) losses«, net of tax	**4,293**	230	411
Replacement cost profit«	**8,073**	23,681	11,428
Net charge (credit) for non-operating items«, net of tax	**4,620**	(10,533)	5,298
Net (favourable) unfavourable impact of fair value accounting effects«, net of tax	**(557)**	280	345
Underlying replacement cost profit«	**12,136**	13,428	17,071
Capital expenditure and acquisitions, on accrual basis	**23,781**	36,612	25,204

[a] Profit attributable to BP shareholders.

Profit for the year ended 31 December 2014 decreased by $19.7 billion compared with 2013. Excluding inventory holding losses, replacement cost (RC) profit also decreased by $15.6 billion compared with 2013. Both results in 2013 included a $12.5 -billion non-operating gain relating to the disposal of our interest in TNK-BP.

After adjusting for a net charge for non-operating items, which mainly related to impairments and further charges associated with the Gulf of Mexico oil spill; and net favourable fair value accounting effects, underlying RC profit for the year ended 31 December 2014 was down by $1.3 billion compared with 2013. The reduction was mainly due to a lower profit in Upstream, partially offset by improved earnings from Downstream.

Profit for the year ended 31 December 2013 increased by $12.4 billion compared with 2012. Excluding inventory holding losses, RC profit also increased by $12.2 billion compared with 2012. The increase in both results was due to a $12.5 -billion gain of disposal of our interest in TNK-BP.

After adjusting for a net credit for non-operating items, which mainly related to the gain on disposal of our interest in TNK-BP and was partially offset by an $845-million write-off and impairments in Upstream and further charges associated with the Gulf of Mexico oil spill; and net unfavourable fair value accounting effects, underlying RC profit for the year ended 31 December 2013 was down by $3.6 billion compared with 2012. This 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 2012 profit was $11.0 billion, RC profit was $11.4 billion and underlying RC profit was $17.1 billion. There was a net post-tax charge of $5.3 billion for non-operating items, which included a $5-billion pre-tax charge relating to the Gulf of Mexico.

More information on non-operating items, and fair value accounting effects, can be found on page 209. See Gulf of Mexico oil spill on page 36 and Financial statements Note 2 for further information on the impact of the Gulf of Mexico oil spill on BP s financial results.

Taxation

The charge for corporate income taxes in 2014 was lower than 2013. The effective tax rate (ETR) was 19% in 2014 (2013 21%, 2012 38%). The low ETR in 2014 reflects the impairment charges on which tax credits arise in relatively high tax rate jurisdictions. The lower ETR in 2013 compared with 2012 primarily reflects the gain on disposal of TNK-BP in 2013 for which there was no corresponding tax charge. The underlying ETR (which excludes non-operating items and fair value accounting effects) on RC profit was 36% in 2014 (2013 35%, 2012 30%).

In the current environment, with our current portfolio of assets, the underlying ETR on RC profit for 2015 is expected to be lower than 2014.

Cash flow and net debt information

			$ million
	2014	2013	2012
Net cash provided by operating activities	**32,754**	21,100	20,479
Net cash used in investing activities	**(19,574)**	(7,855)	(13,075)
Net cash used in financing activities	**(5,266)**	(10,400)	(2,010)
Currency translation differences relating to cash and cash equivalents	**(671)**	40	64
Increase in cash and cash equivalents	**7,243**	2,885	5,458
Cash and cash equivalents at beginning of year	**22,520**	19,635	14,177
Cash and cash equivalents at end of year	**29,763**	22,520	19,635
Gross debt	**52,854**	48,192	48,800
Net debt«	**22,646**	25,195	27,465
Gross debt to gross debt-plus-equity	**31.9%**	27.0%	29.0%
Net debt to net debt-plus-equity«	**16.7%**	16.2%	18.7%

Net cash provided by operating activities

Net cash provided by operating activities for the year ended 31 December 2014 increased by $11.7 billion compared with 2013. Excluding the impacts of the Gulf of Mexico oil spill, net cash provided by operating activities was $32.8 billion for 2014, an increase of $11.6 billion compared with 2013. Profit before taxation was lower but this was partially offset by movements in the adjustments for non-cash items, including depreciation, depletion and amortization, impairments and gains and losses on sale of businesses and fixed assets. Furthermore, 2013 was impacted by an adverse movement in working capital and 2014 was favourably impacted.

The increase in 2013 compared with 2012 primarily benefited from the reduction of $2.3 billion in the cash outflow in respect of the Gulf of Mexico oil spill. Excluding the impacts of the Gulf of Mexico oil spill, net cash provided by operating activities was $21.2 billion for 2013, compared with $22.9 billion for 2012, a decrease of $1.7 billion. The decrease was mainly due to an increase in working capital requirements of $3.9 billion, which was partially offset by a reduction in income tax paid.

Net cash used in investing activities

Net cash used in investing activities for the year ended 31 December 2014 increased by $11.7 billion compared with 2013. The increase reflected a decrease in disposal proceeds of $18.5 billion, partly offset by a $4.9 -billion decrease 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 in 2013. There was also a decrease in our other capital expenditure excluding acquisitions of $2.0 billion.

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The decrease in 2013 compared with 2012 reflected an increase in disposal proceeds of $10.4 billion, 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 $1.3 billion.

There were no significant acquisitions in 2014, 2013 and 2012.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $23.1 billion in 2014 (2013 $30 billion and 2012 $24.8 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.

We expect capital expenditure, excluding acquisitions and asset exchanges, to be around $20 billion in 2015.

Total cash disposal proceeds received during 2014 were $3.5 billion (2013 $22 billion, 2012 $11.6 billion). In 2013 this included $16.7 billion for the disposal of BP s interest in TNK-BP and in 2012 it included $5.6 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. See Financial statements Note 3 for more information on disposals.

Net cash used in financing activities

Net cash used in financing activities for the year ended 31 December 2014 decreased by $5.1 billion compared with 2013. The decrease primarily reflected higher net proceeds of $3.3 billion from long-term financing and a decrease in the net repayment of short-term debt of $1.3 billion. The $8-billion share repurchase programme was completed in July 2014.

The increase in 2013 compared with 2012 primarily reflected the buyback of shares of $5.5 billion, as part of our $8-billion share repurchase programme, lower net proceeds of $1.1 billion from long-term financing and an increase in the net repayment of short-term debt of $1.4 billion.

Total dividends paid in 2014 were 39 cents per share, up 6.8% compared with 2013 on a dollar basis and 1.9% in sterling terms. This equated to a total cash distribution to shareholders of $5.9 billion during the year (2013 $5.4 billion, 2012 $5.3 billion).

Net debt

Net debt at the end of 2014 decreased by $2.5 billion from the 2013 year-end position. The ratio of net debt to net debt plus equity at the end of 2014 increased by 0.5%.

The total cash and cash equivalents at the end of 2014 were $7.2 billion higher than 2013.

We will continue to target our net debt ratio in the 10-20% range while uncertainties remain. Net debt and the ratio of net debt to net debt plus equity are non-GAAP measures. See Financial statements Note 25 for further information on net debt.

For information on financing the group s activities, see Financial statements Note 27 and Liquidity and capital resources on page 211.

Group reserves and production

Total hydrocarbon proved reserves at 31 December 2014, on an oil equivalent basis including equity-accounted entities, decreased by 3% (decrease of 5% for subsidiaries and increase of 1% for equity-accounted entities) compared with 31 December 2013. Natural gas represented about 44% of these reserves (58% for subsidiaries and 27% for equity-accounted entities). The change includes a net decrease from acquisitions and disposals of 39mmboe (all within our subsidiaries). Acquisition activity in our subsidiaries occurred in Azerbaijan, the US and the UK, and divestment activity in our subsidiaries occurred in the US and Brazil.

Our total hydrocarbon production for the group was 2% lower compared with 2013. The decrease comprised a 1% increase (7% increase for liquids and 4% decrease for gas) for subsidiaries and a 7% decrease (13% decrease for liquids and 25% increase for gas) for equity-accounted entities.

For more information on reserves and production, see Oil and gas disclosures for the group on page 219.

	2014	2013	2012
Estimated net proved reserves[a] (net of royalties)			
Liquids«			million barrels
Crude oil[b]			
Subsidiaries«	**3,582**	3,798	4,082
Equity-accounted entities[c]	**5,663**	5,589	5,275
	9,244	9,387	9,357
Natural gas liquids			
Subsidiaries	**510**	551	591
Equity-accounted entities[c]	**62**	131	103
	572	682	693
Total liquids			
Subsidiaries	**4,092**	4,349	4,672
Equity-accounted entities[c]	**5,725**	5,721	5,378
	9,817	10,070	10,050
Natural gas			billion cubic feet
Subsidiaries	**32,496**	34,187	33,264
Equity-accounted entities[c]	**12,200**	11,788	7,041
	44,695	45,975	40,305
Total hydrocarbons«			million barrels of oil equivalent
Subsidiaries	**9,694**	10,243	10,408
Equity-accounted entities[c]	**7,828**	7,753	6,592
	17,523	17,996	17,000
Production[a] (net of royalties)			
Liquids			thousand barrels per day
Crude oil[d]			
Subsidiaries	**844**	789	795
Equity-accounted entities[e]	**979**	1,120	1,137
	1,823	1,909	1,932
Natural gas liquids			
Subsidiaries	**91**	86	96
Equity-accounted entities[e]	**12**	19	27
	103	105	123
Total liquids[f]			

Subsidiaries	**936**	874	891
Equity-accounted entities[e]	**991**	1,139	1,164
	1,927	2,013	2,056
Natural gas			million cubic feet per day
Subsidiaries	**5,585**	5,845	6,193
Equity-accounted entities[e]	**1,515**	1,216	1,200
	7,100	7,060	7,393
Total hydrocarbons[f]			thousand barrels of oil equivalent per day
Subsidiaries	**1,898**	1,882	1,959
Equity-accounted entities[e]	**1,253**	1,348	1,372
	3,151	3,230	3,331

[a] Because of rounding, some totals may not agree exactly with the sum of their component parts.
[b] Includes condensate and bitumen.
[c] Includes BP s share of Rosneft (2014 and 2013) and TNK-BP reserves (2012). See Rosneft on page 33 and Supplementary information on oil and natural gas on page 167 for further information.
[d] Includes condensate.
[e] Includes BP s share of Rosneft (2014 and 2013) and TNK-BP production (2013 and 2012). See Rosneft on page 33 and Oil and gas disclosures for the group on page 219 for further information.
[f] A minor amendment has been made to the split between subsidiaries and equity-accounted entities for the comparative periods.

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Upstream

We continued to actively manage our portfolio to play to our strengths, divesting non-core assets and finding alternative ways to create long-term value.

~

An operator works the controls at the Rumaila oilfield in Iraq. The field extends 50 miles from end to end.

Our business model and strategy

The 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 2014 our activities took place in 28 countries.

With the exception of the US Lower 48 onshore business, 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«.

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

We optimize and integrate the delivery of these activities with support from global functions with specialist areas of expertise: technology, finance, procurement and supply chain, human resources and information technology.

In 2015 our US Lower 48 onshore business began operating as a separate business, with its own governance, processes and systems. This is designed to promote nimble decision making and innovation so that BP can be more competitive in the US onshore market, while maintaining BP s commitment to safe, reliable and compliant operations. The business s approach is to operate in line with industry standards developed within the context of the highly regulated US environment. BP s US Lower 48 business manages a diverse portfolio which includes an extensive unconventional resource base.

Technologies such as seismic imaging, enhanced oil recovery and real-time data support our upstream strategy by helping to gain new access, increase recovery and reserves and improve 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 (including 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 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.
- Prioritizing value over volume:
  - A more focused portfolio with strengthened incumbent positions and reduced operating complexity.
  - Efficient execution of our base activities, a quality set of major projects and leveraging our access and exploration expertise.
- Disciplined investment in three distinctive engines for growth: deep water, gas value chains and giant fields. We maintain a balanced portfolio of opportunities.
- Delivery of competitive operating cash growth through improvements in efficiency and reliability for both operations and investment.
- Strong relationships built on mutual advantage, deep knowledge of the basins in which we operate and technology.

Our performance summary

- For upstream safety performance see page 40.
- Our exploration function gained access to new potential resources covering more than 47,000km^2 in five countries.

We started up seven major upstream projects.

We achieved an upstream BP-operated plant efficiency« of 90%.

Our disposals generated $2.5 billion in proceeds in 2014.

Upstream profitability ($ billion)

See Financial performance on page 25 for an explanation of the main factors influencing upstream profit.

Outlook for 2015

We expect reported production in 2015 to be higher than 2014, mainly reflecting higher entitlements in production-sharing agreement (PSA)« regions on the basis of assumed lower oil prices. Actual reported outcome will depend on the exact timing of project start-ups, OPEC quotas and entitlement impacts in our PSAs. We expect underlying production« in 2015 to be broadly flat with 2014, with the base decline being offset by new major project volumes both from 2014 and 2015.

We expect four major projects to come onstream in 2015 two in Angola and one each in Australia and Algeria.

Capital investment in 2015 is expected to decrease, largely reflecting the lower oil price environment and our commitment to continued capital discipline. The reduction is expected to come primarily from prioritizing activity in our operations, paring back exploration and access spend, and shelving a number of marginal projects.

Financial performance

			$ million
	2014	2013	2012
Sales and other operating revenues[a]	**65,424**	70,374	72,225
RC profit before interest and tax	**8,934**	16,657	22,491
Net (favourable) unfavourable impact of non-operating items« and fair value accounting effects«	**6,267**	1,608	(3,055)
Underlying RC profit before interest and tax	**15,201**	18,265	19,436
Capital expenditure and acquisitions	**19,772**	19,115	18,520
BP average realizations[b]			$ per barrel
Crude oil	**93.65**	105.38	108.94
Natural gas liquids	**36.15**	38.38	42.75
Liquids«	**87.96**	99.24	102.10
			$ per thousand cubic feet
Natural gas	**5.70**	5.35	4.75
US natural gas	**3.80**	3.07	2.32
			$ per barrel of oil equivalent
Total hydrocarbons«	**60.85**	63.58	61.86
Average oil marker prices[c]			$ per barrel
Brent	**98.95**	108.66	111.67
West Texas Intermediate	**93.28**	97.99	94.13
Average natural gas marker prices			$ per million British thermal units
Average Henry Hub gas price[d]	**4.43**	3.65	2.79
			pence per therm
Average UK National Balancing Point gas price[c]	**50.01**	67.99	59.74

[a] Includes sales to other segments.
[b] Realizations are based on sales by consolidated subsidiaries« only, which excludes equity-accounted entities.
[c] All traded days average.
[d] Henry Hub First of Month Index.

Market 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.

The dated Brent price in 2014 averaged $98.95 per barrel, after three consecutive years of prices above $100. Prices averaged about $109 during the first half of 2014, but fell sharply during the second half in the face of continued strong growth of light, sweet oil production in the US and weak global consumption growth. Brent prices ended the year near $55.

The Henry Hub First of Month Index price was up by 21%, year on year, in 2014 (2013, up by 31%).

Brent ($/bbl)

An extremely cold start to 2014 in North America increased heating demand and drained storage levels. US gas supply continued to expand in 2014, reaching yet another record production level, in particular supported by rising liquids-rich gas production.

Henry Hub ($/mmBtu)

The UK National Balancing Point gas price in 2014 fell by 26% compared with 2013 (2013 an increase of 14% on 2012). This reflected milder weather and weak demand in Europe. Lower LNG prices in Asia led to a reduction in the price of spot LNG available for Europe, which contributed to the weakness of European spot prices. For more information on the global energy market in 2014, see page 20.

Financial results

Sales and other operating revenues for 2014 decreased compared with 2013, primarily reflecting lower liquids realizations partially offset by higher production in higher-margin areas, higher gas realizations and higher gas marketing and trading revenues. The decrease in 2013 compared with 2012 primarily reflected lower volumes due to disposals and lower liquids realizations, partially offset by higher gas marketing and trading revenues.

Replacement cost (RC) profit before interest and tax for the segment included a net non-operating charge of $6,298 million. This is primarily related to impairments associated with several assets, mainly in the North

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Sea and Angola reflecting the impact of the lower near-term price environment, revisions to reserves and increases in expected decommissioning cost estimates. This also included a charge to write down the value ascribed to block KG D6 in India as part of the acquisition of upstream interests from Reliance Industries in 2011. The charge arises as a result of uncertainty in the future long-term gas price outlook, following the introduction of a new formula for Indian gas prices, although we do see the commencement of a transition to market-based pricing as a positive step. We expect further clarity on the new pricing policy and the premiums for future developments to emerge in due course. Fair value accounting effects had a favourable impact of $31 million relative to management s view of performance.

The 2013 result included a net non-operating charge of $1,364 million, which included 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 had an unfavourable impact of $244 million from fair value accounting effects. 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.

After adjusting for non-operating items and fair value accounting effects, the decrease in the underlying RC profit before interest and tax compared with 2013 reflected lower liquids realizations, higher costs, mainly depreciation, depletion and amortization and exploration write-offs and the absence of one-off benefits which occurred in 2013 (see below). This was partly offset by higher production in higher-margin areas, higher gas realizations and a benefit from stronger gas marketing and trading activities.

Compared with 2012 the 2013 result 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, one-off benefits related to production taxes and a cost pooling settlement agreement between the owners of the Trans-Alaska Pipeline System (TAPS), and higher gas realizations.

Total capital expenditure including acquisitions and asset exchanges in 2014 was higher compared with 2013. This included $469 million in 2014 relating to the purchase of an additional 3.3% equity in Shah Deniz, Azerbaijan and the South Caucasus Pipeline.

In total, disposal transactions generated $2.5 billion in proceeds during

2014, with a corresponding reduction in net proved reserves of 114mmboe, all within our subsidiaries.

The major disposal transactions during 2014 were the farm-out of a 40% stake in block 61 in the Khazzan field, Oman, to government owned Makarim Gas Development LLC, for $545 million; the sale of our interests in four BP-operated oilfields on the North Slope of Alaska to Hilcorp, including all of BP s interests in the Endicott and Northstar oilfields and a 50% interest in each of the Milne Point field and the Liberty prospect, together with BP s interests in the oil and gas pipelines associated with these fields for $1.25 billion plus an additional carry of up to $250 million, if the Liberty field is developed; and the sale of our interests in the Panhandle West and Texas Hugoton gas fields to Pantera Acquisition Group, LLC for $390 million. Sales transactions are typically subject to post-closing adjustments and future payments depending on oil price and production. More information on disposals is provided in Upstream analysis by region on page 213 and Financial statements Note 3.

Provisions for decommissioning increased from $17.2 billion at the end of 2013 to $18.7 billion at the end of 2014. The increase primarily reflects updated estimates of the cost of future decommissioning, additions and a change in discount rate, partially offset by utilization of provisions, exchange revaluation and impacts of divestments. Decommissioning costs are initially capitalized within fixed assets and are subsequently depreciated as part of the asset.

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.

New access in 2014

We gained access to new potential resources covering more than 47,000km^2 in five countries (Australia, Greenland, UK (North Sea), the US (Gulf of Mexico) and Morocco, which received final government approval in April 2014). In December, we signed a new PSA with the State Oil Company of the Republic of Azerbaijan to jointly explore for and develop potential prospects in the shallow water area around the Absheron Peninsula in the Azerbaijan sector of the Caspian Sea. This is pending final ratification by the government. Additionally, Rosneft and BP signed a heads of agreement in May 2014 relating to a long-term project for the exploration and potential development of the Domanik formations in the Volga-Urals region of Russia.

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In January 2015, we received formal licences for El Matariya and Karawan concessions in Egypt after ratification and finalization of the agreements.

During the year we participated in five discoveries that are potentially commercial including: one in Egypt with the BG-operated Notus well in the El Burg concession; one in the pre-salt play of Angola with the Orca well in Block 20, operated by Cobalt International Energy; one at Xerelete in Brazil s Campos basin, operated by Total; one at Vorlich in the North Sea, which spans the GDF-SUEZ-operated block 30/1f and the BP-operated block 30/1c; and Guadalupe in the deepwater Gulf of Mexico, operated by Chevron.

Exploration and appraisal costs

Excluding lease acquisitions, the costs for exploration and appraisal costs were $2,911 million (2013 $4,811 million, 2012 $4,356 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 31% of exploration and appraisal costs were directed towards appraisal activity. We participated in 67 gross (32.75 net) exploration and appraisal wells in 10 countries.

Exploration expense

Total exploration expense of $3,632 million (2013 $3,441 million, 2012 $1,475 million) included the write-off of expenses related to unsuccessful drilling activities or lease expiration in the Lower 48 ($665 million), Algeria ($524 million), India ($139 million), the Gulf of Mexico ($500 million), Brazil ($368 million), China ($112 million), Angola ($110 million), Morocco ($83 million) and others ($133 million). In addition, $395 million was written off KG D6 in India as a result of uncertainty in the future long-term gas price outlook (see page 216).

Upstream reserves

Estimated net proved reserves[a] (net of royalties)

	2014	2013	2012
Liquids			million barrels
Crude oil[b]			
Subsidiaries«	**3,582**	3,798	4,082
Equity-accounted entities[c]	**702**	729	813
	4,283	4,527	4,895
Natural gas liquids			
Subsidiaries	**510**	551	591
Equity-accounted entities[c]	**16**	16	25
	526	567	616
Total liquids			
Subsidiaries[d]	**4,092**	4,349	4,672
Equity-accounted entities[c]	**717**	745	838
	4,809	5,094	5,510
Natural gas			billion cubic feet
Subsidiaries[e]	**32,496**	34,187	33,264
Equity-accounted entities[c]	**2,373**	2,517	2,549

	34,869	36,704	35,813
Total hydrocarbons	million barrels of oil equivalent		
Subsidiaries	**9,694**	10,243	10,408
Equity-accounted entities[c]	**1,126**	1,179	1,277
	10,821	11,422	11,685

[a] Because of rounding, some totals may not agree exactly with the sum of their component parts.
[b] Includes condensate and bitumen.
[c] BP s share of reserves of equity-accounted entities in the Upstream segment. During 2014, 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 21 million barrels (21 million barrels at 31 December 2013 and 14 million barrels at 31 December 2012) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC.
[e] Includes 2,519 billion cubic feet of natural gas (2,685 billion cubic feet at 31 December 2013 and 2,890 billion cubic feet at 31 December 2012) 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 segment s total hydrocarbon reserves on an oil equivalent basis, including equity-accounted entities at 31 December 2014, decreased by 5% (5% for subsidiaries and 4% for equity-accounted entities) compared with reserves at 31 December 2013.

Proved reserves replacement ratio«

The proved reserves replacement ratio for the Upstream segment in 2014, excluding acquisitions and disposals, was 31% for subsidiaries and equity-accounted entities (2013 93%), 29% for subsidiaries alone (2013 105%) and 43% for equity-accounted entities alone (2013 30%). For more information on proved reserves replacement for the group see page 219.

Developments

The map on page 26 shows our major development areas. We achieved seven major project start-ups in 2014: the Chirag oil project in Azerbaijan; Na Kika Phase 3, Mars B and Atlantis North expansion Phase 2 in the Gulf of Mexico; CLOV in Angola; Kinnoull in the North Sea and Sunrise in Canada. In addition to starting up major projects, 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 an oil and gas discovery, Orca, in the pre-salt play of Angola in Block 20 (BP 30%), operated by Cobalt International Energy, Inc. and the CLOV project reached plateau production of 160mboe/d.

Azerbaijan the Shah Deniz and South Caucasus Pipeline consortia awarded further key contracts for the development of the Shah Deniz Stage 2 and South Caucasus Pipeline expansion projects. The BP-operated Azerbaijan International Operating Company celebrated the 20th anniversary of the Azeri-Chirag-Gunashli PSA.

North Sea we continued to see high levels of activity, including a new discovery, Vorlich, in the central North Sea (see page 28); progress in the major redevelopment of the west of Shetland Schiehallion and Loyal fields; and the restart of operations at the Rhum field. BP has been granted seven awards in the UK government s 28th licensing round. The blocks are located in three of our core areas: to the north of our Magnus field, next to Vorlich, and west of our Kinnoull development. The government is still to award some blocks in this round. These blocks are undergoing environmental assessment.

Gulf of Mexico we made a new discovery Guadalupe and were awarded 51 blocks in the March and August Gulf of Mexico lease sales. At the end of the year we had 10 rigs operating. Following our strategic divestment programme, we now have a focused portfolio with growth potential around four operated and three non-operated hubs.

Development expenditure of subsidiaries incurred in 2014, excluding midstream activities, was $15.1 billion (2013 $13.6 billion, 2012 $12.6 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. It includes production from conventional and unconventional (coalbed methane, shale) assets. The principal areas of production are Angola, Argentina, Australia, Azerbaijan, Egypt, Trinidad, the UAE, the UK and the US.

Production (net of royalties)[a]

	2014	2013	2012
Liquids			thousand barrels per day
Crude oil			
Subsidiaries	**844**	789	795
Equity-accounted entities	**163**	294	281
	1,007	1,083	1,076
Natural gas liquids			
Subsidiaries	**91**	86	96
Equity-accounted entities	**7**	8	7
	99	94	103
Total liquids[b]			
Subsidiaries	**936**	874	891
Equity-accounted entities	**170**	302	288
	1,106	1,176	1,179
Natural gas			million cubic feet per day
Subsidiaries	**5,585**	5,845	6,193
Equity-accounted entities	**431**	415	416
	6,016	6,259	6,609
Total hydrocarbons[b]			thousand barrels of oil equivalent per day
Subsidiaries	**1,898**	1,882	1,959
Equity-accounted entities	**245**	374	360
	2,143	2,256	2,319

[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] A minor amendment has been made to the split between subsidiaries and equity-accounted entities for the comparative periods.

Our total hydrocarbon production for the segment in 2014 was 5% lower compared with 2013. The decrease comprised a 1% increase (7% increase for liquids and 4% decrease for gas) for subsidiaries and a 35% decrease (44% decrease for liquids and 4% increase for gas) for equity-accounted entities compared with 2013. Divestments in 2014 accounted for 2% of the year-on-year production decrease. For more information on production see Oil and gas disclosures for the group on page 219.

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 2.2% higher compared with 2013. This primarily reflects strong Gulf of Mexico performance that was not impacted by weather, higher entitlements from lower oil prices and ADMA offshore concession (BP 14.67%) benefiting from higher OPEC nomination for Abu Dhabi.

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 (including liquefied natural gas (LNG)), 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 our 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 and risk management 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, support group LNG activities, and to manage market price risk and create incremental trading opportunities through the use of commodity derivative contracts. This activity also enhances margins and generates fee income from sources such as the management of price risk on behalf of third-party customers.

The group s risk governance framework seeks to manage and oversee the financial risks associated with this trading activity, as described in Financial statements Note 27.

The group uses a range of commodity derivative contracts, storage and transport contracts in connection with its trading activities. The range of contracts that the group enters into is described in Glossary commodity trading contracts on page 252.

Downstream

In 2014 we saw continued improvement in our process safety and delivered strong operational performance resulting in profit and operating cash flow growth.

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The storage tanks, pipes and towers at BP s Rotterdam refinery, which can run at least 70 different kinds of crude.

Our business model and strategy

Our Downstream segment has significant operations in Europe, North America and Asia, and also manufactures and markets products in Australasia, Africa and Central and South America.

Downstream is the product and service-led arm of BP, made up of three businesses:

Fuels includes refineries, fuels marketing and convenience retail businesses, together with global oil supply and trading activities that make up fuels value chains (FVCs). We sell refined petroleum products including gasoline, diesel and aviation fuel.

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, mainly using proprietary BP technology. These products are then used by others to make essential consumer products such as paint, plastic bottles and textiles.

We aim to run safe and reliable operations across all our businesses, supported by leading brands and technologies, to deliver high-quality products and services to meet our customers needs.

Our strategy focuses on improving returns, growing operating cash flow«, and building a quality Downstream business that aims to lead the industry as measured by net income per refining barrel. Our five strategic priorities are:

Safe and reliable operations this remains our first priority and we continue to drive improvement in personal and process safety performance.

Advantaged manufacturing we aim to continue building a top quartile refining business by having a competitively advantaged portfolio which is underpinned by operations excellence. In petrochemicals we seek to create a business with higher earnings potential which is significantly more robust to a bottom of cycle environment.

Fuels marketing and lubricants we will invest in higher returning businesses which have operating cash flow growth potential.

Portfolio quality we will maintain our focus on quality by high-grading of assets combined with capital discipline. Where businesses do not fit our strategic frame, we will seek to divest.

Simplification and efficiency we have launched a simplification and efficiency programme to support performance improvement and to make our businesses even more competitive.

Implementing this strategy is expected to lead to a growing downstream earnings profile and increasingly make the business more robust to external environmental impacts. Growing operating cash flows and capital discipline should ensure that Downstream remains a source of increasing cash flow for BP.

Our performance summary

For downstream safety performance see page 41.

We continue to deliver strong operational performance across our refining system with the Whiting refinery now fully onstream.

We acquired the aviation fuel business, Statoil Fuel and Retail Aviation AS, to expand our Air BP business in Scandinavia.

We launched a new product, *Castrol EDGE* boosted with *Titanium Fluid Strength Technology* in our lubricants business.

- We sold our lubricants global aviation turbine oils business and completed the sale of our LPG marketing businesses.
- We announced that we will halt refining operations at the Bulwer refinery in Australia in 2015.
- In petrochemicals, we decided to invest and retrofit some of our operations in the US and Europe with new proprietary technology while ceasing certain other operations in our aromatics business as a result of our strategic review.

Downstream profitability ($ billion)

See Financial performance on page 30 for the main factors influencing downstream profit.

Outlook for 2015

- We anticipate a weaker refining environment due to narrowing crude differentials in the low crude price environment.
- We expect the financial impact of refinery turnarounds to be comparable to that in 2014.
- We expect gradual improvement in the petrochemicals margin environment.

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Financial performance

			$ million
	2014	2013	2012
Sale of crude oil through spot and term contracts	**80,003**	79,394	56,383
Marketing, spot and term sales of refined products	**227,082**	258,015	274,666
Other sales and operating revenues	**16,401**	13,786	15,342
Sales and other operating revenues[a]	**323,486**	351,195	346,391
RC profit before interest and tax[b]			
Fuels	**2,830**	1,518	1,403
Lubricants	**1,407**	1,274	1,276
Petrochemicals	**(499)**	127	185
	3,738	2,919	2,864
Net (favourable) unfavourable impact of non-operating items« and fair value accounting effects«			
Fuels	**389**	712	3,609
Lubricants	**(136)**	(2)	9
Petrochemicals	**450**	3	(19)
	703	713	3,599
Underlying RC profit before interest and tax[b]			
Fuels	**3,219**	2,230	5,012
Lubricants	**1,271**	1,272	1,285
Petrochemicals	**(49)**	130	166
	4,441	3,632	6,463
Capital expenditure and acquisitions	**3,106**	4,506	5,249

[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.

Financial results

Sales and other operating revenues in 2014 decreased compared with 2013 primarily due to falling crude prices. The increase in 2013, compared with 2012, reflected higher prices largely offset by lower volumes and foreign exchange losses.

The 2014 result included a net non-operating charge of $1,570 million, primarily relating to impairment charges in our petrochemicals and fuels businesses, while 2013 and 2012 results included impairment charges in our fuels business, which were mainly associated with our disposal programme. In addition, fair value accounting effects had a favourable impact of $867 million in 2014 versus unfavourable impacts in 2013 and 2012.

After adjusting for non-operating items and fair value accounting effects, underlying replacement cost (RC) profit before interest and tax in 2014 was higher than 2013 but lower than 2012.

Our fuels business

The fuels strategy focuses primarily on fuels value chains (FVCs). These include large-scale, highly upgraded, feedstock-advantaged refineries which are integrated with logistics and marketing businesses.

We believe that having a quality refining portfolio connected to strong marketing positions is core to our integrated FVC businesses as this provides optimization opportunities in highly competitive markets. We look to build on our strong portfolio of refining assets and, through advantaged crude, optimize across the supply chain.

We have improved our refining portfolio quality in terms of crude feedstock and location advantage, scale and have sustained competitive complexity through portfolio rationalization and selective investment. Across all regions we expect to operate our portfolio at top quartile availability and with improved efficiency.

We continue to grow our fuels marketing businesses, including retail, through differentiated marketing offers and distinctive partnerships. We partner with leading retailers globally, creating distinctive offers that deliver good returns and reliable profit and cash generation.

Underlying RC profit before interest and tax was higher than 2013, mainly due to improved fuels marketing performance, increased heavy crude processing and higher production, mainly as a result of the ramp-up of operations at our Whiting refinery following the modernization project. This was partially offset by a weaker refining environment. Compared with 2012, the 2013 results were impacted by significantly weaker refining margins, reduced throughput due to the planned Whiting refinery outage as a result of our 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.

Refining marker margin«

We track the margin environment by 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. In addition, the RMM does not include estimates of energy or other variable costs.

				$ per barrel
Region	Crude marker	**2014**	2013	2012
US North West	Alaska North Slope	**16.6**	15.2	18.0
US Midwest	West Texas Intermediate	**17.4**	21.7	27.8
Northwest Europe	Brent	**12.5**	12.9	16.1
Mediterranean	Azeri Light	**10.6**	10.5	12.7
Australia	Brent	**13.5**	13.4	14.8
BP RMM		**14.4**	15.4	18.2

BP refining marker margin ($/bbl)

The average global RMM in 2014 was $14.4/bbl, the lowest level since 2010 and $1.0/bbl lower than 2013. This was largely due to the narrower West Texas Intermediate-Brent spread as improving pipeline and rail logistics in the US reduced the discount of US domestic crude oil relative to the international benchmark.

Refining

At 31 December 2014 we owned or had a share in 14 refineries producing refined petroleum products that we supply to retail and commercial customers. For a summary of our interests in refineries and average daily crude distillation capacities see page 217.

In 2014, refinery operations were strong, with Solomon refining availability sustained at around 95% and utilization rates of 88% for the year. Overall refinery throughputs in 2014 were lower than those in 2013, mainly due to the divestment of the Texas City and Carson refineries.

	2014	2013	2012
Refinery throughputs[a]	thousand barrels per day		
US[b]	**642**	726	1,310
Europe	**782**	766	751
Rest of world	**297**	299	293
Total	**1,721**	1,791	2,354
			%
Refining availability«	**94.9**	95.3	94.8
Sales volumes	thousand barrels per day		
Marketing sales[c]	**2,872**	3,084	3,213
Trading/supply sales[d]	**2,448**	2,485	2,444
Total refined product sales	**5,320**	5,569	5,657
Crude oil[e]	**2,360**	2,142	1,518
Total	**7,680**	7,711	7,175

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

[b] The Texas City and Carson refineries were both divested in 2013.

[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. 88,000 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 that includes pipelines, storage terminals and tankers for road and rail. We seek to drive for excellence in operational and transactional processes and deliver compelling customer offers in the various markets where we operate. For example, in 2014 we added the capability to receive additional US shale crudes by rail at our Cherry Point refinery in Washington. This increases the use of location-advantaged crudes at this refinery, improving access and diversification of crude slates.

We supply fuel and related retail services to consumers through company-owned and franchised retail sites, as well as other channels, including dealer wholesalers and jobbers. We also supply commercial customers within the transport and industrial sectors.

	Number of retail sites operated under a BP brand		
Retail sites[f]	**2014**	2013	2012
US	**7,100**	7,700	10,100
Europe	**8,000**	8,000	8,300
Rest of world	**2,100**	2,100	2,300
Total	**17,200**	17,800	20,700

[f] The number of retail sites includes sites not operated by BP but instead operated by dealers, jobbers, franchisees or brand licensees 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.

Retail is the most material element of our fuels marketing operations and has good exposure to growth markets. We have distinctive partnerships with leading retailers in six countries and plan to expand elsewhere. Retail is a significant source of growth today and is expected to be so in the future. See Driving success below.

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 our FVCs to maintain a single interface with oil trading markets and to operate with a single set of trading compliance and risk management processes, systems and controls. The oil trading function (including support functions) has trading offices in Europe, the US and Asia. Our presence in the more actively-traded regions of the global oil markets supports overall understanding of the supply and demand forces across these markets. 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 we will look to optimize value across the supply chain. For example, we will often sell our own crude and purchase alternative crudes from third parties for our refineries where this will provide incremental margin.

Second, the function aims to create and capture incremental trading opportunities by entering into a full range of exchange-traded commodity derivatives, over-the-counter 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, which seeks to manage and oversee the financial risks associated with this trading activity, is described in Financial statements Note 27.

The range of contracts that the group enters into is described in Glossary commodity trading contracts on page 252.

Aviation

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. We are one of the world s largest global aviation fuels suppliers. Air BP serves many major commercial airlines as well as the general aviation sectors. We have marketing sales of approximately 400,000 barrels per day. For details of acquisitions in 2014, see Running reliably on page 40.

Our lubricants business

Our lubricants strategy is to focus on our premium brands and growth markets while leveraging technology and customer relationships. With more than 50% of profit generated from growth markets and continued growth in premium lubricants, we have an excellent base for further expansion and sustained profit growth.

Our lubricants business manufactures and markets lubricants and related products and services to the automotive, industrial, marine and energy markets across the world. Our key brands are *Castrol*, *BP* and *Aral*. *Castrol* is a recognized brand worldwide which we believe provides us with significant competitive advantage. In technology, we apply our expertise to create quality lubricants and high-performance fluids for customers in on-road, off-road, sea and industrial applications globally.

We are one of the largest purchasers of base oil in the market, but have chosen not to produce it or manufacture additives at scale. Our participation choices in the value chain are focused on areas where we can leverage competitive differentiation and strength, such as:

- Applying cutting-edge technologies in the development and formulation of advanced products.
- Creating and developing product brands and clearly communicating their benefits to our customers.
- Building and extending our relationships with customers to better understand and meet their needs.

The lubricants business delivered an underlying RC profit before interest and tax which is largely consistent with 2013 and 2012 levels. The 2014 result saw an underlying 6% year-on-year improvement in results, which was offset by adverse foreign exchange translation impacts.

Our petrochemicals business

Our petrochemicals strategy is to own and develop petrochemicals value chain businesses that are built around proprietary technology to deliver leading cost positions against our competition. We manufacture and market four main product lines:

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

We also produce a number of other specialty petrochemicals products.

We aim to improve our earnings potential and make the business more robust to a bottom of cycle environment. We are taking steps to significantly improve the cash break even performance of the business. This should improve our earnings potential and make the business more robust to a bottom of cycle environment. The actions to achieve this include:

- Restructuring a significant portion of our portfolio, primarily in our aromatics business, to shut down older capacity in the US and Asia and assess disposal options for less advantaged assets.
- Retrofitting our best technology in our advantaged sites to reduce overall operating costs.
- Growing third-party licensing income to create additional value.
- Delivering operational improvements focused on turnaround efficiency and improved reliability.

In addition to the assets we own and operate, we have also invested in a number of joint arrangements in Asia, where our partners are leading companies within their domestic market. An example of this is our latest generation technology PTA plant in China, which we are building with our partner, Zhuhai Port Co. The plant is currently commissioning with planned start-up in the first half of 2015.

In 2014 the petrochemicals business delivered a lower underlying RC profit before interest and tax compared with 2013 and 2012. This result reflected a continuation of the weak margin environment, particularly in the Asian aromatics sector, and unplanned operational events.

Our petrochemicals production in 2014 was flat compared with 2013 and slightly lower than 2012, with the low margin environment in 2014 and 2013 driving reduced output.

In November 2014 we announced plans to invest more than $200 million to upgrade PTA plants at Cooper River in South Carolina and Geel in Belgium using our latest proprietary technology. We expect these investments to significantly increase manufacturing efficiency at these facilities. We plan to continue deploying our technology in new asset platforms to access Asian demand and advantaged feedstock sources.

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Rosneft

BP holds a unique position in Russia through its 19.75% share in Rosneft.

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Rosneft discovery in the South Kara Sea.

BP and Rosneft

- 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.
- Russia has significant hydrocarbon resources and will continue to play an important role in long-term energy supply to the global economy.
- BP believes the primary sources of value to BP shareholders from its investment in Rosneft will be potential long-term share price appreciation and dividend growth.
- BP is positioned to contribute to Rosneft s strategy implementation through collaboration on technology and best practice. We also have the potential to undertake standalone projects with Rosneft, both in Russia and internationally.
- We remain committed to our strategic investment in Rosneft while complying with all relevant sanctions.

2014 summary

- US and EU sanctions were imposed on certain Russian activities, individuals and entities, including Rosneft.
- BP received $693 million, net of withholding taxes, in July representing our share of Rosneft s dividend of 12.85 Russian roubles per share for 2013.

Rosneft and BP signed a contract in June to supply BP with up to 12 million tons of oil products over five years. A syndicate of banks, through a pre-export financing agreement, made a payment of approximately $1.935 billion to Rosneft.

Rosneft and BP signed a heads of agreement in May relating to a long-term project for the exploration and potential development of the Domanik formations in the Volga-Urals region of Russia.

Rosneft and BP concluded framework agreements in May to enable technical collaboration between the parties. Work is ongoing in a number of areas pursuant to these agreements in both upstream and downstream.

Bob Dudley serves on the Rosneft board of directors, and its strategic planning committee.

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 has a major resource base of hydrocarbons onshore and offshore, with assets in all key hydrocarbon regions of Russia: Western Siberia, Eastern Siberia, Timan-Pechora, Volga-Urals, North Caucasus, the continental shelf of the Arctic Sea, and the Far East.

Rosneft participates in international exploration projects or has operations in countries including the US, Canada, Vietnam, Venezuela, Brazil, Algeria, United Arab Emirates, Turkmenistan and Norway.

To progress Arctic exploration, it conducted exploration drilling with ExxonMobil in the South Kara Sea and announced a hydrocarbon discovery in September. Exxon subsequently suspended its participation in this project with Rosneft due to sanctions. Rosneft also began production drilling in the Sea of Okhotsk in September 2014, and continued to grow its gas business increasing gas production from 38 to 57bcm as well as advancing plans for the development of LNG export capacity.

Downstream

Rosneft is the leader of the Russian refining industry. It owns and operates 10 refineries in Russia and also has an interest in four refineries in Germany through its Ruhr Oel GmbH partnership with BP. It continued implementation of the modernization programme for its Russian refineries in 2014 to significantly upgrade and expand refining capacity.

Rosneft refinery throughput in 2014 amounted to 2,027mb/d. As at 31 December 2014, Rosneft owned and operated more than 2,500 retail service stations, representing the largest network in Russia. This included BP-branded sites acquired as part of the TNK-BP acquisition in 2013 which continue to operate under the BP brand under a licence agreement with BP. 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 segment result includes equity-accounted earnings from Rosneft, representing BP s share in Rosneft.

		$ million
	2014[a]	2013[b]

Profit before interest and tax[c d]	**2,076**	2,053
Inventory holding (gains) losses«	**24**	100
RC profit before interest and tax	**2,100**	2,153
Net charge (credit) for non-operating items«	**(225)**	45
Underlying RC profit before interest and tax«	**1,875**	2,198
Average oil marker prices		$ per barrel
Urals (Northwest Europe CIF)	**97.23**	107.38
Russian domestic oil	**50.40**	54.97

[a] The operational and financial information of the Rosneft segment for 2014 is based on preliminary operational and financial results of Rosneft for the three months ended 31 December 2014. Actual results may differ from these amounts.

[b] From 21 March 2013.

[c] 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.

[d] Includes $25 million (2013 $5 million loss) of foreign exchange losses arising on the dividend received.

Replacement cost (RC) profit before interest and tax for the segment included a non-operating gain of $225 million, relating to Rosneft s sale of its interest in the Yugragazpererabotka joint venture«. In addition, the result was affected by an unfavourable duty lag effect, lower oil prices and other items, partially offset by certain foreign exchange effects which had a favourable impact on the result. See also Financial statements Notes 15 and 30 for other foreign exchange effects.

« Defined on page 252.

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Balance sheet

	2014	\$ million 2013
Investments in associates«[a] (as at 31 December)	**7,312**	13,681

Production and reserves

	2014 [b]	2013
Production (net of royalties) (BP share)[c]		
Liquids« (mb/d)		
Crude oil[d]	**816**	643
Natural gas liquids	**5**	7
Total liquids	**821**	650
Natural gas (mmcf/d)	**1,084**	617
Total hydrocarbons« (mboe/d)	**1,008**	756
Estimated net proved reserves (net of royalties) (BP share)		
Liquids (million barrels)		
Crude oil[d]	**4,961**	4,860
Natural gas liquids	**47**	115
Total liquids	**5,007**	4,975
Natural gas (billion cubic feet)	**9,827**	9,271
Total hydrocarbons (mmboe)	**6,702**	6,574

[a] See Financial statements Note 15 for further information.
[b] The operational and financial information of the Rosneft segment for 2014 is based on preliminary operational and financial results of Rosneft for the three months ended 31 December 2014. Actual results may differ from these amounts.
[c] 2013 reflects production for the period 21 March to 31 December, averaged over the full year. Information on BP s share of TNK-BP s production for comparative periods is provided on pages 222 and 223.
[d] Includes condensate.

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Other businesses

and corporate

Comprises our biofuels and wind businesses, shipping, treasury and corporate activities including centralized functions.

p

Crew carrying out mooring operations on the deck of BP s oil tanker, *British Chivalry*, as it berths in Singapore.

Financial performance

			$ million
	2014	2013	2012
Sales and other operating revenues[a]	**1,989**	1,805	1,985
RC profit (loss) before interest and tax	**(2,010)**	(2,319)	(2,794)
Net (favourable) unfavourable impact of non-operating items«	**670**	421	798
Underlying RC profit (loss) before interest and tax«	**(1,340)**	(1,898)	(1,996)
Capital expenditure and acquisitions	**903**	1,050	1,435

[a] Includes sales to other segments.

The replacement cost (RC) loss before interest and tax for the year ended 31 December 2014 was $2.0 billion (2013 $2.3 billion, 2012 $2.8 billion). The 2014 result included a net charge for non-operating items of $670 million (2013 $421 million, 2012 $798 million). This represented restructuring provisions and impairments, principally in respect of our biofuels businesses in the UK and US.

After adjusting for these non-operating items, the underlying RC loss before interest and tax for the year ended 31 December 2014 was $1.3 billion (2013 $1.9 billion, 2012 $2.0 billion). This result reflected improved shipping, biofuels and wind performance and a number of one-off credits.

Biofuels

Our investment in alternative energies is focused on biofuels, where our strategy is to focus on the conversion of cost-advantaged and sustainable feedstocks that are materially scalable and can be competitive without subsidies.

We operate three sugar cane mills in Brazil producing bioethanol and sugar and exporting power to the local grid. We continue to evaluate options to increase production at these facilities and completed work on expanding ethanol production capacity at one mill as planned.

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 our partner DuPont, we are undertaking research into the production of biobutanol under the company name Butamax.

Across our biofuels business, BP s share of ethanol-equivalent production (which includes ethanol and sugar) for 2014 was 653 million litres compared with 521 million litres in 2013. The majority of this production was from BP s sugar cane mills in Brazil.

Wind

We have a wind energy business in the US, with interests in 16 operating wind farms. Gross generating capacity from this portfolio is 2,585MW of electricity. Our focus is on safe operations and optimizing performance at our owned and joint venture« wind farms.

Based on our financial stake, BP s net wind generation capacity[b]« was 1,588 MW at 31 December 2014, compared with 1,590 MW at 31 December 2013. Our net share of wind generation for 2014 was 4,617 GWh, compared with 4,203 GWh a year ago.

[b] Capacity figures include 32MW in the Netherlands managed by our Downstream segment.

Shipping

The primary purpose of BP s shipping and chartering activities is the transportation of the group s hydrocarbon products using a combination of BP-operated, time-chartered and spot-chartered vessels. Surplus capacity may also be used to transport third-party products. All vessels conducting BP shipping activities are subject to our health, safety, security and environmental requirements. At 31 December 2014, our fleet included four Alaskan vessels, 46 BP-operated and 41 time-chartered vessels for our deep-sea, international oil and gas shipping operations. In December 2014 BP shipping entered into contracts with Daewoo Shipbuilding & Marine Engineering in South Korea for the construction of LNG tankers to be delivered in 2018 and 2019.

Treasury

Treasury manages the financing of the group centrally, with responsibility for managing the group s debt profile, share buyback programmes and dividend payments while ensuring liquidity is sufficient to meet group requirements. It also 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 27.

Insurance

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. We bear losses as they arise, rather than spreading them 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

Other businesses and corporate annual charges, excluding non-operating items, are expected to be around $1.6 billion in 2015.

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Gulf of Mexico oil spill

Economic and environmental restoration progress continues, while BP makes its case in court.

p

BP restoration projects in Louisiana include creating a fish hatchery and rebuilding and restoring beach, dune and marsh habitat on a number of coastal islands.

Key events

In April the US Coast Guard ended active clean-up along the Gulf of Mexico shoreline, with any future identification of residual oil to be dealt with through the National Response Center process.

The federal district court in New Orleans ruled in September that the discharge of oil was the result of the gross negligence and wilful misconduct of BP Exploration & Production Inc. BP has appealed this ruling.

In January 2015 the district court ruled that 3.19 million barrels of oil were discharged into the Gulf of Mexico and that BP was not grossly negligent in its source control efforts. We have also appealed this ruling.

BP continued to challenge the implementation of the settlement agreement with the Plaintiffs Steering Committee, including issues around compensation for losses with no apparent connection to the spill. In December, the US Supreme Court declined BP s petition to review the lower court decisions relating to these issues.

As at the end of 2014, the cumulative pre-tax income statement charge since the incident amounted to $43.5 billion. This does not include amounts that BP does not consider possible to measure reliably at this time. The magnitude and timing of all possible obligations continue to be subject to significant uncertainty.

The cumulative charges to be paid from the Deepwater Horizon Oil Spill Trust fund reached $20 billion in 2014. Subsequent additional costs are being charged to the income statement as they arise.

Environmental and economic restoration

We have made significant progress in completing the response to the accident and supporting environmental and economic recovery efforts in affected areas. The US Coast Guard ended patrols and operations on the final shoreline miles in Louisiana in April 2014. The Coast Guard has now transitioned all shoreline areas to their National Response Center process. If residual oil from the Deepwater Horizon incident is later identified and requires removal, BP will take action at the direction of the Coast Guard.

BP is responsible for the reasonable and necessary costs of assessing injury to natural resources resulting from the oil spill and of restoration as defined under the Oil Pollution Act of 1990 (OPA 90). In 2014 activity was focused on natural resource damage assessment and further progress was made on early restoration work.

Natural resource damage assessment and early restoration projects

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. The plan will address the identified injuries including the recreational use of these resources, as well as an estimated cost to implement it. By the end of 2014, BP had spent approximately $1.3 billion to support the assessment process. See *gulfsciencedata.bp.com* for environmental data collected through the natural resource damage assessment process.

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 incident. BP and the trustees, as at December 2014, had reached agreement on a total of 54 early restoration projects that are expected to cost approximately $700 million, of which $629 million had been funded by the end of 2014. BP is providing project funding in exchange for restoration credits to be applied against the trustees final assessment of BP s natural resource damages funding obligations.

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 on marine and coastal ecosystems. BP has contributed $215 million to the programme as at 31 December 2014.

Economic recovery

BP continued to support economic recovery efforts in local communities through a variety of actions and programmes in 2014. By 31 December 2014, BP had spent $13.4 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.

See *bp.com/gulfofmexico* for more information on environmental and economic restoration activities.

Multi-district litigation proceedings in New Orleans

The multi-district litigation trial relating to liability, limitation, exoneration and fault allocation (part of MDL 2179) began in the federal district court in New Orleans in February 2013.

Phase 1 causes of the accident and allocation of fault

The district court issued its ruling on the first phase of the trial in September 2014. It found that BP Exploration & Production Inc. (BPXP the BP group company that conducts exploration and production operations in the Gulf of Mexico), BP America Production Company and various other parties are each liable under general maritime law for the blowout, explosion and oil spill from the Macondo well. With respect to the United States claim against BPXP under the Clean Water Act, the district court found that the discharge of oil was the result of BPXP s gross negligence and wilful misconduct and that BPXP is therefore subject to enhanced civil penalties. BP does not believe that the evidence at trial supports a finding of gross negligence and wilful misconduct and has appealed the Phase 1 ruling.

A provision of $3,510 million was recognized in 2010 for estimated civil penalties under Section 311 of the Clean Water Act. BP continues to believe that a provision of $3,510 million represents a reliable estimate of the amount of the liability if the appeal is successful and this provision, calculated on the basis of the previous assumptions, has been maintained in the accounts. If BP is unsuccessful in its appeal, and the ruling of gross negligence and wilful misconduct is upheld, the maximum penalty that could be imposed is up to $4,300 per barrel. Based upon this penalty rate and the district court s ruling of the number of barrels spilled, which, as noted above is also subject to appeal, the maximum penalty could be up to $13.7 billion. The court has wide discretion in its application of statutory penalty factors and we are therefore unable to determine a reliable estimate for any additional penalty which might apply should the gross negligence finding be upheld.

Phase 2 efforts to stop the flow of oil and the volume of oil spilled

The district court issued its ruling on the second phase of the trial in January 2015. It found that 3.19 million barrels of oil were discharged into the Gulf of Mexico. In addition, the district court found that BP was not grossly negligent in its source control efforts. We have also appealed this Phase 2 ruling.

Penalty phase

The penalty phase of the trial concluded in February 2015. In this phase, the district court will determine the amount of civil penalties owed to the United States under the Clean Water Act. This will be based on the court s rulings or ultimate determinations on appeal as to the presence of negligence, gross negligence or wilful misconduct and the volume of oil spilled, as well as the application of the penalty factors under the Clean Water Act.

BP is not currently aware of the timing of the district court s ruling for the penalty phase.

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 was established to act on behalf of individual and business plaintiffs in MDL 2179. During 2014, amounts paid out under the PSC settlements totalled approximately $600 million.

Individual and business claims

As part of its monitoring of payments made by the court-supervised 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. BP has also raised issues about misconduct and inefficiency in the facility administering the settlement.

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 when the revenues and expenses were recorded at different times. In May 2014, the district court approved the claims administrator s revised matching policy reflecting this order and the policy is now in effect. The PSC has filed a motion with the district court to alter or amend the policy.

In September 2014 the district court denied BP s motion to order the return of excessive payments made by the Deepwater Horizon Court Supervised Settlement Program under the matching policy in effect before the district court s December 2013 ruling requiring a claimant s revenue to be matched with variable expenses. BP has appealed this decision to the US Court of Appeals for the Fifth Circuit (Fifth Circuit).

Following the ruling by the district court, which was affirmed by the Fifth Circuit, that the settlement agreement did not contain a causation requirement beyond the revenue and related tests set out in an exhibit to that agreement, the district court in May dissolved the injunction that had halted the processing and payment of business economic loss claims and instructed the claims administrator to resume the processing and payment of claims. In August BP petitioned the US Supreme Court for review of the Fifth Circuit s decisions relating to compensation of claims for losses with no apparent connection to the Deepwater Horizon spill. In December 2014 the US Supreme Court denied BP s petition for review.

Business economic loss claims continue to be assessed and paid under the revised matching policy. The deadline for submitting claims is 8 June 2015.

In September 2014 BP sought to remove Patrick Juneau from his roles as claims administrator and settlement trustee for the economic and property damages settlement for reasons including a conflict of interest. This was denied by the district court and BP has appealed this decision.

Medical claims

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 was one year from the effective date.

Process safety and ethics monitors

Two independent monitors a process safety monitor and an ethics monitor were appointed under the terms of the criminal plea agreement BP reached with the US government in 2012 to resolve all federal criminal claims arising out of the Deepwater Horizon incident. Under the terms of the agreement, BP is taking additional actions, enforceable by the court, to further enhance the safety of drilling operations in the Gulf of Mexico.

The process safety monitor is reviewing and providing recommendations concerning BPXP s process safety and risk management procedures for deepwater drilling in the Gulf of Mexico.

The ethics monitor is reviewing and providing recommendations concerning BP s ethics and compliance programme.

The monitors have interviewed BP employees, reviewed policies and procedures and made site visits in preparation for their initial reports, which will be delivered in 2015.

A 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. See *bpxpcompliancereports.com* for annual updates on BP s compliance with the plea agreement.

Other legal proceedings

BP is subject to a number of different legal proceedings in connection with the Deepwater Horizon incident in addition to the legal proceedings relating to the PSC settlements and the multi-district litigation proceedings in New Orleans. For more information see Legal proceedings on page 228.

OPA 90 and other civil claims

BP p.l.c., BPXP and various other BP entities have been among the companies named as defendants in approximately 3,000 civil lawsuits resulting from the accident and oil spill, including the claims by several states and local government entities. The majority of these lawsuits assert claims under OPA 90, 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 into MDL 2179.

Alabama, Mississippi, Florida, Louisiana, Texas and various local government entities have 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 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 90, not supported by documentation and to be substantially overstated.

Securities litigation proceedings

The multi-district litigation proceedings pending in federal court in Houston (MDL 2185), including a purported class action on behalf of purchasers of American Depositary Shares under US federal securities law, are continuing. A jury trial is scheduled to begin in January 2016.

SEC settlement

In connection with the 2012 settlement with the SEC resolving the SEC s Deepwater Horizon-related civil claims, in August 2014, the final instalment of $175 million was paid under the civil penalty of $525 million.

US Environmental Protection Agency (EPA) suspension and debarment

In March 2014, BP p.l.c., BPXP, and all other BP entities that the EPA had suspended from receiving new federal contracts or renewing existing ones entered into an administrative agreement with the EPA resolving all issues related to suspension or debarment arising from the Deepwater Horizon incident. The administrative agreement restores the eligibility of BP entities to enter into new contracts or leases with the US government. Under the terms and conditions of the administrative agreement, which applies for five years, BP has agreed to safety and operations, ethics and compliance and corporate governance requirements.

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Financial update

The group income statement for 2014 includes a pre-tax charge of $819 million in relation to the Gulf of Mexico oil spill. The charge for the year reflects additional litigation and claims costs and the ongoing costs of the Gulf Coast Restoration Organization. As at 31 December 2014, the total cumulative charges recognized to date amount to $43.5 billion. 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 and the timing of such costs will be dependent on many factors, including in relation to any new information or future developments. These could have a material impact on our consolidated financial position, results and cash flows.

BP has provided for spill response costs, environmental expenditure, litigation and claims and Clean Water Act penalties that can be measured reliably. The cumulative income statement charge does not include amounts for obligations that BP considers are not possible to measure reliably at this time, such as:

- Natural resource damages, except for reasonable costs for damage assessment, the $1-billion allocation for early restoration projects and associated legal costs.

- Any obligation that may arise from securities-related litigation.

- The cost of business economic loss claims under the PSC settlement not yet received, or received but not yet processed, or processed but not yet paid (except where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility).

- Claims asserted in civil litigation, including any further litigation through excluded parties from the PSC settlement.

- Any further liability for the Clean Water Act penalty arising in the event the gross negligence finding is upheld.

- Any further obligation that may arise from state and local claims.

The additional amounts payable for these and other items could be considerable. More details regarding the impacts and uncertainties relating to the Gulf of Mexico oil spill can be found in Risk factors on page 48, Legal proceedings on page 228 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 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 cumulative charges to the Trust had reached $20 billion in 2014. Subsequent additional costs over and above those provided within the $20 billion, are being charged to the income statement as they arise.

Payments made out of the Trust during 2014 totalled $1.7 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 programme and other resolved items. As at 31 December 2014, the aggregate cash balances in the Trust and the associated qualified settlement funds amounted to $5.1 billion, including $1.1 billion remaining in the seafood compensation fund, from which a further $0.5 billion partial distribution started in early 2015, and $0.4 billion held for natural resource damage early restoration projects.

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Corporate responsibility

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

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A safety and health specialist tests a confined space to make sure it s safe for entry at the Kwinana refinery in Western Australia.

Safety

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

Our operating management system (OMS)« sets out BP s principles for good operating practice.

By the end of 2014, we had completed 25 of the 26 recommendations from BP s internal investigation regarding the Deepwater Horizon accident, the Bly Report.

Contractors carried out 52% of the 357 million hours worked by BP in 2014.

Process safety events

(number of incidents)

Recordable injury frequency

(workforce incidents per 200,000 hours worked)

[a] API and OGP 2014 data reports are not available until May 2015.

Additional information on our safety, environmental and social performance is available in our Sustainability Report. See *bp.com/sustainability* for case studies, country reports and an interactive tool for health, safety and environmental data.

Group safety performance

In 2014, BP reported three fatalities; a fall from height in the UK, an incident involving a forklift in Indonesia, and an incident that occurred inside a process vessel in Germany. We deeply regret the loss of these lives.

Personal safety performance

	2014	2013	2012
Recordable injury frequency (group)[b]	**0.31**	0.31	0.35
Day away from work case frequency[c] (group)[b]	**0.081**	0.070	0.076
Severe vehicle accident rate[d]	**0.132**	0.120	0.130

[b] Incidents per 200,000 hours worked.
[c] Incidents that resulted in an injury where a person is unable to work for a day (shift) or more.
[d] Number of vehicle incidents that result in death, injury, a spill, a vehicle rollover, or serious disabling vehicle damage per one million kilometres travelled.

Process safety performance

	2014	2013	2012
Tier 1 process safety events«	**28**	20	43
Tier 2 process safety events	**95**	110	154
Loss of primary containment number of all incidents[e]	**286**	261	292
Loss of primary containment number of oil spills[f]	**156**	185	204
Number of oil spills to land and water	**63**	74	102
Volume of oil spilled (thousand litres)	**400**	724	801
Volume of oil unrecovered (thousand litres)	**155**	261	320

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

We report our safety performance using industry metrics including the American Petroleum Institute (API) RP-754 standard. These include 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. Tier 2 process safety events are those of lesser consequence than tier 1. We take a long-term view on process safety indicators because the full benefit of the decisions and actions in this area is not always immediate.

We seek to record all losses of primary containment (LOPC), regardless of the volume of the release and report on losses over a severity threshold. These include unplanned or uncontrolled releases from a tank, vessel, pipe, rail car or equipment used for containment or transfer. Our 2014 data reflects increases in part due to the introduction of enhanced automated monitoring for many remote sites in our Lower 48 business.

Our performance in these areas over time suggests that our focus on safety is having a positive impact. However, we need to continue to remain vigilant and focused on delivering safe, reliable and compliant operations.

Managing safety

We are working to continuously improve safety and risk management across BP. Our operating businesses are responsible for identifying and managing risks and bringing together people with the right skills and competencies to address them. They are also required to carry out self-verification and are subject to independent scrutiny and assurance. Our safety and operational risk team works alongside our operating businesses to provide oversight and technical guidance, while members of our group audit teams visit certain sites, including third-party rigs, to check how they are managing risks.

« Defined on page 252.

Each business segment has a safety and operational risk committee, chaired by the business head, to oversee the management of safety and operational risk in their respective areas of the business. In addition, the group operations risk committee facilitates the group chief executive s oversight of safety and operational 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 safety and operational risk on the management of the highest priority risks. SEEAC also receives 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 46.

Operating management system (OMS)

BP s OMS is a group-wide framework designed to help us manage risks in our operating activities. It brings together BP requirements on health, safety, security, the environment, social responsibility and operational reliability, as well as related issues, such as maintenance, contractor relations and organizational learning, into a common management system. Any necessary variations in the application of OMS in order to meet local regulations or circumstances are subject to a governance process.

OMS also helps us improve the quality of our operating activities. All businesses covered by OMS undertake an annual performance improvement cycle and assess alignment with the OMS framework. Recently acquired operations need to transition to OMS. We review and amend our group requirements within OMS from time to time to reflect BP s priorities and experience or changing external regulations. See page 41 for information about contractors and joint arrangements«.

Capability development

We aim to equip our staff with the skills needed to run safe and efficient operations. Our OMS capability development programmes cover areas such as process safety, risk, and safety leadership. Our applied deepwater well control course uses simulator facilities to train key members of rig teams, including contractors. We have conducted more than 35 classes for rig crews from around the world since the course began in October 2012.

Security and crisis management

The scale and spread of BP s operations means we must prepare for a range of 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. See page 42 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, the Algerian state oil and gas company Sonatrach and Statoil, came under armed terrorist attack. Algerian military action regained control of the site. Forty people, including four BP employees, and a former employee, lost their lives in the incident. This was a tragic and unprecedented event which impacted many employees and their families.

BP participated fully in the UK Coroner s inquest, which we considered the most effective means of providing a greater understanding of what happened. The UK Coroner handed down his verdicts, conclusions and detailed factual findings on 26 February 2015.

Since the attack, BP and Statoil have jointly carried out an extensive review of security arrangements in Algeria and have been working with Sonatrach and the Algerian authorities on a programme of security enhancements. The Coroner accepted the opinion of his independent security expert who endorsed the security measures now in place and commented that in his opinion the security enhancements now provide a significantly safer environment for the staff working there.

Upstream safety

Safety performance

	2014	2013	2012
Recordable injury frequency	**0.23**	0.32	0.32
Day away from work case frequency	**0.051**	0.068	0.053
Loss of primary containment incidents number	**187**	143	151

Safer drilling

Our global wells organization is responsible for planning and executing all our wells operations across the world. It is also responsible for establishing standards on compliance, risk management, contractor management, performance indicators, technology and capability for our well operations.

Completing the Bly Report recommendations

BP s investigation into the Deepwater Horizon accident, the Bly Report, made 26 recommendations aimed at further reducing risk across our global drilling activities. A total of 25 recommendations had been completed by the end of 2014.

We expect the final recommendation to be completed by the end of 2015, as scheduled. This recommendation involves verifying the implementation of revised well control and monitoring standards to BP-owned and BP-contracted offshore rigs. It takes time to fully implement as it requires training a large proportion of our global wells operating personnel on the revised standards.

Our group audit team has verified closure of the recommendations.

See *bp.com/26recommendations* for the Bly Report recommendations.

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The BP board appointed Carl Sandlin as independent expert in 2012 to provide an objective assessment of BP s global progress in implementing the recommendations from the Bly Report. Mr Sandlin also provides his views on the organizational effectiveness and culture of the global wells organization, and process safety observations.

As part of his activities in 2014, Mr Sandlin conducted his third round of visits to regional wells teams with active drilling operations. Mr Sandlin visited 10 regions in total. During each visit he conducted reviews with senior managers, and held discussions with key wells personnel and drilling contractors on site.

Mr Sandlin is engaged through to June 2016.

Downstream safety

Safety performance

	2014	2013	2012
Recordable injury frequency	**0.34**	0.25	0.33
Day away from work case frequency	**0.121**	0.063	0.089
Severe vehicle accident rate	**0.09**	0.10	0.16
Loss of primary containment incidents number	**82**	101	117

We take measures to prevent leaks and spills at our refineries and other downstream facilities through well-designed, well-maintained and properly operated equipment. We also seek to provide safe locations, emergency procedures and other mitigation measures in the event of a release, fire or explosion.

We focus on managing the highest priority risks associated with our storage, handling and processing of hydrocarbons. We use technology, such as automated systems, which are intended to prevent our gasoline storage tanks from overfilling, to help manage our operations within safe operating and design limits. In 2014 a total of 12 facilities participated in our exemplar programme, which aims to help sites apply our OMS using continuous improvement processes.

Process safety expert

The board appointed Duane Wilson as process safety expert for our downstream activities in 2012 for a three-year term and assigned him to work in a global capacity with the business. Mr Wilson provided an independent perspective on the progress that BP s fuels, lubricants and petrochemicals businesses were making toward becoming industry leaders in process safety performance.

Working with contractors and partners

BP, like our industry peers, rarely works in isolation we need to work with contractors, suppliers and partners to carry out our operations. In 2014, 52% of the 357 million hours worked by BP were carried out by contractors.

Our ability to be a safe and responsible operator depends in part on the capability and performance of those who help us carry out our operations. We therefore seek to identify and manage risks in the supply chain relating to areas such as safety, corruption and money laundering, and aim to have suitable provisions in our contracts with contractors, suppliers and partners.

Contractors

We expect and encourage our contractors and their employees to act in a way that is consistent with our code of conduct. Our OMS includes requirements and practices for working with contractors.

We seek to set clear and consistent expectations of our contractors. Our standard model upstream contracts, for example, include health, safety, security and environmental requirements. Bridging documents are necessary in some cases to define how our safety management system and those of our contractors co-exist to manage risk on site.

To help us manage risks effectively and take advantage of economies of scale, we are focusing on developing deeper, longer-term relationships with selected upstream contractors. We have established global agreements in areas such as engineered equipment and well services.

Our partners in joint arrangements

We seek to work with companies that share our commitment to ethical, safe and sustainable working practices. Our code of conduct states that we seek to clearly communicate our relevant expectations to our business partners, agreeing contractual obligations where applicable.

We have a group framework for identifying and managing BP s exposure related to safety, operational, and bribery and corruption risk from our participation in non-operated joint arrangements.

Typically, our level of influence or control over a joint arrangement is linked to the size of our financial stake compared with other participants. In some joint arrangements we act as the operator. Our OMS applies to the operations of joint arrangements only where we are the operator.

In other cases, one of our 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 generally available as a reference point for engagement with operators and co-venturers.

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The Toledo refinery in Ohio processes around 160,000 barrels of crude oil each day to make gasoline, jet fuel and other products.

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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

Our operating sites can have a lifespan of several decades and our operations are expected to work to reduce their impacts and risks. This starts in early project planning and continues through operations and decommissioning.

Our operating management system« (OMS) includes practices that set out requirements and guidance for how we identify and manage environmental and social impacts. The practices apply to our major projects«, projects that involve new access, those that could affect an international protected area and some BP acquisition negotiations.

In the early planning stages of these projects, we complete a screening process to identify the most significant environmental and social impacts. We completed the process for 19 projects in 2014. Following screening, projects are required to carry out impact assessments, identify mitigation measures and implement these in project design, construction and operations.

BP s environmental expenditure in 2014 totalled $4,024 million (2013 $4,288 million, 2012 $7,230 million). For a breakdown of environmental expenditure see page 225. This figure includes a charge of $190 million relating to the Gulf of Mexico oil spill. For reference, expenditure related to the Gulf of Mexico oil spill was a credit of $66 million in 2013 and a charge of $919 million in 2012. For Regulation of the group s business Environmental regulation see page 225.

We review our management of material issues such as greenhouse gas emissions, water, sensitive and protected areas and oil spill response. This includes examining emerging risks and actions taken to mitigate them.

Oil spill preparedness and response

Our requirements for oil spill preparedness and response planning, and crisis management incorporate what we have learned over many years of operation, and specifically from the Deepwater Horizon accident. Almost three quarters of our businesses with the potential to spill oil have updated oil spill planning scenarios and response strategies, in line with our new requirements issued in 2012. We aim to complete the remaining updates by the end of 2016.

Meeting the requirements is a substantial piece of work and we believe this has already resulted in a significant increase in our oil spill response capability. For example, this includes using specialized modelling techniques that help predict the impact of potential spills, the provision of stockpiles of dispersants and the use of new tools for environmental monitoring, such as aerial and underwater robotic vehicles.

Enhancing response capabilities

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 be affected by oil spills and develop appropriate response strategies. We are implementing a mapping system that brings together geographical, operational, infrastructure, socio-economic, biological and habitat information to help us identify and better understand potential impacts of an oil spill.

We are also testing the applicability of a number of emerging technologies for oil spill response, including the use of robotic vehicles with camera sensors to locate spills and provide remote visibility for oil spill response at sea.

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 2014 we shared lessons on dispersant use and oil spill response technologies with government regulators in Angola, the UK and the US.

See page 39 for information on volume of oil spilled by our operations in 2014, including volume of oil unrecovered.

Climate change

BP believes that climate change is an important long-term issue that justifies global action. We are taking steps to address carbon risk and collaborating with others on climate change issues. For example, we require our operations to incorporate energy use considerations in their business plans and to assess, prioritize and implement technologies and systems that could improve usage. We factor a carbon cost into our own investments and engineering designs for large new projects, and invest in lower-carbon energy products. We seek to address potential climate change impacts on our new projects in the design phase. We have guidance for existing operations and projects on how to assess potential climate risks and impacts to enable mitigation steps to be incorporated into project planning, design and operations.

Greenhouse gas emissions

We report on direct and indirect GHG emissions on a carbon dioxide-

equivalent (CO_2e) basis. Direct emissions include CO_2 and methane from the combustion of fuel and the operation of facilities, and indirect emissions include those resulting from the purchase of electricity, heat, steam or cooling. In 2014 we changed our GHG reporting boundary from a BP equity-share basis to an operational control basis.

Our approach to reporting GHG emissions broadly follows the IPIECA/ API/IOGP Petroleum Industry Guidelines for Reporting GHG Emissions (the IPIECA guidelines). 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 it is not practical to collect this data.

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Greenhouse gas emissions ($MteCO_2e$)

	2014	2013	2012
Operational control[a]			
Direct emissions	**54.1**		
Indirect emissions	**7.2**		
BP equity share[b]			
Direct emissions	**48.6**	50.3[c]	59.8
Indirect emissions	**6.6**	6.6	8.4

[a] Operational control data comprises 100% of emissions from activities that are operated by BP, going beyond the IPIECA guidelines by including emissions from certain other activities such as contracted drilling activities. Data for emissions on an operational control basis was not available prior to 2014.

[b] BP equity share comprises our share of BP s consolidated entities and equity-accounted entities, other than BP s share of TNK-BP and Rosneft. Rosneft s emissions data can be found on its website.

[c] The reported 2013 figure of 49.2 $MteCO_2e$ has been amended to 50.3 $MteCO_2e$.

The decrease in our GHG emissions is primarily due to the sale of our Carson and Texas City refineries in the US as part of our divestment programme. See *bp.com/greenhousegas* for more information about our GHG emissions from upstream production, refining throughput and chemicals produced.

Intensity

In 2014 we changed the intensity ratio we report on from a financial to a production-based one. The ratio of our total GHG emissions reported on an operational control-based boundary to gross production was 0.25$teCO_2e$/te production in 2014. Gross production comprises upstream production, refining throughput and petrochemicals produced.

In 2013 we reported the ratio of our total GHG emissions on a BP equity-share basis to adjusted revenue of those entities or share of entities included in GHG reporting. This was 0.15kte/ $million. Adjusted revenue reflects total revenues and other income, less gains on sales of businesses and fixed assets.

Greenhouse gas regulation

GHG regulation is increasing globally. For example, we are seeing the growth of emission pricing schemes in Europe, California and China, additional monitoring regulations in the US and increased focus on reducing flaring and methane emissions in many jurisdictions.

We expect that GHG regulation 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. In industrialized countries, our standard cost assumption is currently $40 per tonne of CO_2 equivalent. We use this cost as a basis for assessing the economic value of the investment and as one consideration in optimizing the way the project is engineered with respect to GHG emissions.

See page 225 for information on other environmental regulations.

Water

BP recognizes the importance of managing fresh water use and water discharges effectively in our operations and evaluates risks, including water scarcity, wastewater disposal and the long-term social and environmental pressures on local water resources.

We have invested in a specialist water treatment company to support operations in areas of water scarcity. The company manufactures desalinization and brine management systems and we aim to trial these technologies at our operations.

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 risks.

Water and sand constitute on average 99.5% of the injection material used in hydraulic fracturing. Some of the chemicals that are added to this when used in certain concentrations, are classified as hazardous by the relevant regulatory authorities. BP works with service providers to minimize their use where possible. We list the chemicals we use in the fracturing process in material safety data sheets at each site. We also 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* or other state-designated websites.

We aim to minimize air pollutant and GHG emissions, such as methane, at our operating sites. For example, we use a process called green completions at the majority of our gas operations in the US. This process, which we have been using since 2001, captures natural gas that would otherwise be flared or vented during the completion and commissioning of wells.

Our US Lower 48 onshore business s approach is to operate in line with industry standards developed within the context of the highly regulated US environment.

See *bp.com/unconventionalgas* for information about our approach to unconventional gas and hydraulic fracturing.

Canada s oil sands

BP is involved in three oil sands lease areas in Canada. Sunrise Phase 1, operated by Husky Energy, started up at the end of 2014 and we expect first oil to be recovered in the first quarter of 2015. Pike Phase 1, operated by Devon Energy, was granted regulatory approval in November 2014 and is at the design and planning stage. 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. Projects are managed through governance committees, with equal representation from BP and our partners, and approval rights laid out in agreements with our partners.

See *bp.com/oilsands* for information on BP s investments in Canada s oil sands.

Human rights

We are committed to conducting our business in a manner that respects the rights and dignity of all people. We 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. We set out our commitments in our human rights policy. Our code of conduct references the policy, requiring employees to report any human rights abuse in our operations or in those of our business partners.

We are delivering our human rights policy by implementing the relevant sections of the United Nations Guiding Principles on Business and Human Rights and incorporating them into the processes and policies that govern our business activities. Our action plan aims to achieve closer alignment with the UN Guiding Principles over a number of years using a risk-based approach. Representatives from key functions, including human resources, ethics and compliance, procurement, security, and safety and operational risk oversee the plan s implementation.

In 2014 our actions included:

- Human rights training events for more than 270 people, including awareness training for relevant senior leadership teams and representatives from functions such as procurement, shipping, finance and legal.

- The inclusion of human rights clauses in a number of our standard model contracts.

- Participation in the work of oil and gas industry organization IPIECA on developing shared industry approaches to managing human rights risks in the supply chain and guidance on responding to community grievances.

- Continued implementation of the Voluntary Principles on Security and Human Rights, with periodic internal assessments to identify areas for improvement.

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Construction work on the Sunrise energy project, based in the Canadian oil sands of northern Alberta.

See *bp.com/humanrights* for more information about our approach to human rights.

Business ethics

Bribery and corruption are significant risks in the oil and gas industry. We have a responsibility to our shareholders and the countries and communities in which we do business to be ethical and lawful in all our dealings. Our code of conduct explicitly states that we do not tolerate bribery and corruption in any of its forms.

Our group-wide anti-bribery and corruption policy applies to all BP-operated businesses. The policy governs areas such as appropriate clauses in contracts, risk assessments and training. We target training on a risk basis and to those employees for whom it is thought to be most relevant, for example, given specific incidents or the nature or location of their role.

Financial transparency

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 preparing to comply with the transposed EU Accounting Directive in the UK and are participating in the development of industry guidance. We are awaiting publication of the final rules of the US Dodd-Frank Act, expected to be issued before the end of 2015.

As a founding member of the Extractive Industries Transparency Initiative (EITI), BP works with governments, non-governmental organizations and international agencies to improve transparency and disclosure of payments to governments. We support governments efforts towards EITI certification in countries where we operate and have worked with many countries on implementation of their EITI commitments, including Australia, Azerbaijan, Indonesia, Iraq, Norway, Trinidad & Tobago, the UK and the US.

Enterprise and community development

We run programmes to help build the skills of businesses and to develop the local supply chain in a number of locations. For example, in Indonesia, we provide one-on-one business consultancy and technical assistance to local businesses during the tender process.

BP s community investments support development that meets local needs and are relevant to our business activities. We contributed $85 million in social investment in 2014.

See *bp.com/society* for more information about our social contribution.

Employees

We seek employees who have the right skills and who understand and embody the values and expected behaviours that guide everything we do.

BP headcount

Number of employees at 31 December[a]	**2014**	2013	2012
Upstream	**24,400**	24,700	24,200
Downstream	**48,000**	48,000	51,800
Other businesses and corporate	**12,100**	11,200	10,400
Total	**84,500**	83,900	86,400

[a] Reported to the nearest 100. For more information see Financial statements Note 33.

The above table includes:

	2014	2013	2012
Retail staff	**14,400**	14,100	14,700
Agricultural, operational and seasonal workers in Brazil	**5,300**	4,300	3,500

At the end of December 2014, we had 84,500 employees. This includes 14,400 service station staff and 5,300 agricultural, operational and seasonal workers in Brazil, which has increased by 1,000 in 2014 due to the expansion of one of our sugar cane processing mills which was completed in 2014. Meanwhile, operational headcount decreased in other areas. We expect our number of employees to align with BP s smaller footprint in 2015 and 2016 as we right-size the organization as part of our response to a lower oil price.

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 use these values as part of our recruitment, promotion and individual performance assessment processes. See *bp.com/values* for more information.

Our people

We aim to develop the talents of our workforce with a focus on maintaining safe and reliable operations, engaging and developing our employees, and increasing the diversity of our workforce.

The group people committee, chaired by the group chief executive, has overall responsibility for key policy decisions relating to employees and governance of BP s people management processes. In 2014 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.

Attracting and retaining our people

The complex projects we work on require a wide range of specialist skills from the capability to explore for new sources of energy through to transporting and distributing hydrocarbons safely across the world. We have a bias towards building capability and promoting from within the organization. Where necessary, we complement this with selective external recruitment. In 2014, 84% of new senior leaders were recruited from within the organization.

A total of 670 graduates joined BP in 2014. We target the fields of science, technology, engineering and maths and run initiatives and awareness days at universities and colleges. We also run future leader programmes to recruit post-graduates. In 2014, 37% of our graduate intake were women and 50% were from outside the UK and US.

We conduct external assessments for people entering senior managerial roles to help achieve rigour and objectivity in our hiring and talent processes. These provide an in-depth analysis of leadership behaviour and whether candidates have the necessary experience and skills for the role.

Building enduring capability

Our development opportunities help to build the diverse skills and expertise that we need. We provide a range of opportunities for our employees, with an increased focus on on-the-job learning. This can include mentoring, team development days, workshops, seminars, online learning and international assignments.

A career transition is a critical moment in an employee s professional growth. We have moved towards prioritizing learning at these points, for example, for those joining BP or moving into a new level of management. We also offer in-role development that covers a range of levels and subject areas, from effective planning to inclusive leadership and change management. Employees from 51 countries attended leadership training, delivered in six different languages in 2014.

Through our internal academies, we provide leading technical, functional, compliance and leadership learning opportunities. In 2014, we launched five academies including the operating management system (OMS) academy that provides training to operations personnel on implementing and applying OMS.

Diversity

As a global business, we aim for a workforce 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 women to represent at least 25% of our group leaders the most senior managers of our businesses and functions by 2020. We continue to support the UK government s review of gender diversity on boards, undertaken by Lord Davies in 2011. Currently we have two women on our board. We are actively seeking qualified candidates and remain committed to Lord Davies goal of a quarter of our board to be female by the end of 2015. For more information on our board composition see page 58.

Workforce by gender

Numbers as at 31 December	Male	Female	Female %
Board directors	12	2	14
Group leaders	426	95	18
Subsidiary« directors	776	125	14
All employees	58,700	25,800	31

At the end of 2014, 22% of our group leaders came from countries other than the UK and the US, compared with 14% in 2000. We have continued to increase the number of local leaders and employees in our operations so that they reflect the communities in which we operate. This is monitored at a local, business and national level.

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.

We aim to ensure equal opportunity in recruitment, career development, promotion, training and reward for all employees regardless of race, colour, national origin, religion, gender, age, sexual orientation, gender

identity, marital status, disability, or any other characteristic protected by applicable laws. Where existing employees become disabled, our policy is to provide continuing employment and training wherever possible.

Employee engagement

Executive team members hold regular meetings and webcasts with employees around the world. Team 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.

Each year, we conduct a survey to gather employees views on a wide range of business topics and to identify areas where we can improve. Approximately 38,000 people in 70 countries completed our 2014 survey. We measure employee engagement with our strategic priorities using questions about perceptions of BP and how it is managed in terms of leadership and standards. This measure remained stable in 2014 at 72% (2013 72%, 2012 71%).

Business leadership teams review the results of the survey and agree actions to address focus areas. The 2014 survey found that employees remain clear about the safety procedures, standards and requirements that apply to them and that pride in working at BP has increased steadily since 2011. Understanding and support of BP s strategy is strong at senior levels, but needs further communication and engagement across the organization this is a focus area for 2015. Scores related to development and career opportunities have fallen slightly compared to 2013. We have been making changes to how we deliver learning and manage talent and we expect to see benefits in the longer term.

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 group-wide equity plan which allows employee participation at different levels globally and is linked to the company s performance.

The BP code of conduct

Our code of conduct is based on our values and clarifies the principles and expectations for everyone who works at BP. It applies to all employees, officers and members of the board.

Employees, contractors or other third parties who have a question about our code of conduct or see something they feel to be unsafe, unethical or potentially harmful can get help through OpenTalk, a confidential helpline operated by an independent company.

In 2014 1,114 people contacted OpenTalk with concerns or enquiries (2013 1,121, 2012 1,295). The most common concerns 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.

We take steps to identify and correct areas of non-conformance and take disciplinary action where appropriate. In 2014, our businesses dismissed 157 employees for non-conformance with our code of conduct or unethical behaviour (2013 113). This excludes dismissals of staff employed at our retail service stations for incidents such as thefts of small amounts of money. We have enhanced our human resources processes, resulting in improved identification and recording of code-related dismissals.

Policy on political activity

We do not use BP funds or resources to support any political candidate or party. 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 provides administrative support to the BP employee political action committee to facilitate employee involvement and to assess whether contributions comply with the law and satisfy all necessary reporting requirements.

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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 48.

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 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 and to the board on a periodic basis on how significant 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. BP requirements, which take into account applicable laws and regulations, underpin the practical plans developed to help reduce risk and deliver strong, sustainable performance. For example, our operating management system (OMS)« integrates BP requirements on health, safety, security, environment, social responsibility, operational reliability and related issues.

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 using a standard framework for collating risk data, assessing risk management activities, making further improvements and planning new activities.

Oversight and governance functional leadership, the executive team, the board and relevant committees provide oversight to identify, understand and endorse management of 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 significant 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, as to 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 investment decision risks.
g Group ethics and compliance committee for legal and regulatory compliance and ethics risks.
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 58.

Risk management processes

As part of BP s annual planning process, we review the group s principal risks and uncertainties. These may be updated throughout the year in response to changes in internal and external circumstances.

We aim for a consistent basis of measuring risk to allow comparison on a like-for-like basis, taking into account potential likelihood and impact, and to inform how we prioritize specific risk management activities and invest resources to manage them.

Our risk profile

The nature of our business operations is long term, resulting in many of our 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.

We identify those risks as having a high priority for particular oversight by the board and its various committees in the coming year. Those identified for 2015 are listed on page 47. These may be updated throughout the year in response to changes in internal and external circumstances.

The oversight and management of other risks is undertaken in the normal course of business throughout the business and in executive and board committees. For example market pricing and liquidity reviews are conducted on a regular basis by the board and executive committees, including the group financial risk committee, to consider how we respond to market conditions and when making or reviewing investment decisions. For further information see page 10.

There can be no certainty that our risk management activities will mitigate or prevent these, or other risks, from occurring.

Further details of the principal risks and uncertainties we face are set out in Risk factors on page 48.

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Risks for particular oversight by the board and its committees in 2015

The risks for particular oversight by the board and committees in 2015 remain the same as those for 2014 except that we have replaced risks associated with delivery of our 10-point plan, which has now been delivered, with those relating to major project delivery one of our group key performance indicators.

Gulf of Mexico oil spill

A wide range of risks have arisen as a result of the Gulf of Mexico 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 while protecting and defending BP s interests.

The committee s responsibilities include oversight and review of the following activities: the legal strategy for litigation; 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 and administrative agreements arising out of the accident and oil spill.

See Legal proceedings page 228, Financial statements Note 2 and Gulf of Mexico committee page 69 for further information.

Strategic and commercial risks

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, and heightened political or social tensions or changes in key relationships could adversely affect the group.

We seek to actively manage this risk through development and maintenance of relationships with governments and stakeholders and becoming trusted partners in each country and region. In addition, we closely monitor events (such as the situation that arose in Ukraine in 2014) and implement risk mitigation plans where appropriate.

Major project« delivery

Renewing our portfolio requires ongoing innovation and development in exploration, production, processing and distribution. Major projects contribute significantly to reshaping our portfolio and delivering our strategy.

To manage the risks associated with major project delivery, each stage of a project s life cycle must meet certain criteria to proceed to the next stage, or it will be re-assessed to improve value or be discontinued. Additionally, executive directors regularly review capital allocation at the resource commitment meetings. In the upstream our global projects organization focuses specifically on major projects and the risks to their delivery. We undertake post-project evaluations to review decision-making processes, project execution and project outcomes, and share these with other major projects as appropriate to support continuous improvement.

For information on our major projects portfolio see page 26, and for a recent example of how we remodel projects see Increasing value on page 21.

Cybersecurity

The threats to the security of our digital infrastructure continue to evolve rapidly 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, testing of cyber response procedures and close co-operation with authorities. Over the past few years our employee campaigns on topics such as email phishing and the protection of our information and equipment have helped to raise awareness of these issues.

Safety and operational risks

Process safety, personal safety and environmental risks

The nature of the group s operating activities 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.

Our OMS helps us manage these risks and drive performance improvements. It sets out the rules and principles which govern key risk management activities such as inspection, maintenance, testing, business continuity and crisis response planning and competency development. 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.

For more information on safety and our OMS see page 39.

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 information security.

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. We continue to monitor the situation in the Middle East and North Africa closely.

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 and training covering areas such as anti-bribery and corruption, anti-money laundering, competition/anti-trust law and international trade regulations. We seek to keep abreast of new regulations and legislation and plan our response to them. We offer an independent confidential helpline, OpenTalk, for employees, contractors and other third parties. Under the terms of the US Department of Justice settlement, an ethics monitor will also review and provide recommendations concerning BP s ethics and compliance programme.

Find out more about our code of conduct, our business ethics and the ethics monitor on pages 45, 44 and 37 respectively.

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 manage these risks, including guidelines specific to trading, and 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.

For further information see Upstream gas marketing and trading activities on page 28, Downstream supply and trading on page 31 and Financial statements Note 27.

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Risk factors

The risks discussed below, separately or in combination, could have a material adverse effect on the implementation of our strategy, our business, financial performance, results of operations, cash flows, liquidity, prospects, shareholder value and returns and reputation.

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), including the amount of claims, fines and penalties that become payable by BP (including as a result of any ultimate determination of BP s appeal of the ruling of gross negligence), the outcome or resolution of current or future litigation and any costs arising from any longer-term environmental consequences of the incident, the impact of the incident on our reputation and the resulting possible impact on our licence to operate. The provisions recognized in the income statement represent the current best estimates of expenditures required to settle certain present obligations that can be reliably estimated at the end of the reporting period, and there are future expenditures for which we currently cannot measure our obligations reliably. These uncertainties are likely to continue for a significant period. See Financial statements Note 2.

The risks associated with the incident could also heighten the impact of other risks the group is exposed to as described below.

Strategic and commercial risks

Prices and markets our financial performance is subject to fluctuating prices of oil, gas, refined products, exchange rate fluctuations and the general macroeconomic outlook.

Oil, gas and product prices are subject to international supply and demand and margins can be volatile. Political developments, increased supply from new oil and gas sources, technological change, global economic conditions and the influence of OPEC can impact supply and prices for our products. Decreases in oil, gas or product prices could have an adverse effect on revenue, margins and profitability and, if significant, we may have to write down assets and re-assess the viability of certain projects. A prolonged period of low prices may impact our cash flows, profit, capital expenditure and ability to maintain our long-term investment programme. Conversely, an increase in oil, gas and product prices may not improve margin performance as there could be increased fiscal take, cost inflation and more onerous terms for access to resources. The profitability of our refining and petrochemicals activities can be volatile, with periodic over-supply or supply tightness in regional markets and fluctuations in demand.

Exchange rate fluctuations can create currency exposures and impact underlying costs and revenues. Crude oil prices are generally set in US dollars, while products vary in currency. Many of our major project« development costs are denominated in local currencies, which may be subject to fluctuations against the US dollar.

Access, renewal and reserves progression our inability to access, renew and progress upstream resources in a timely manner could adversely affect our long-term replacement of reserves.

Delivering our group strategy depends on our ability to continually replenish a strong exploration pipeline of future opportunities to access and produce oil and natural gas. Competition for access to investment opportunities, heightened political and economic risks in certain countries where significant hydrocarbon basins are located and increasing technical challenges and capital commitments may adversely affect our strategic progress. This, and our ability to progress upstream resources and sustain long-term reserves replacement, could impact our future production and financial performance.

Major project delivery failure to invest in the best opportunities or deliver major projects successfully could adversely affect our financial performance.

We face challenges in developing major projects, particularly in geographically and technically challenging areas. Operational challenges and poor investment choice, efficiency or delivery at any major project that underpins production or production growth could adversely affect our financial performance.

Geopolitical we are exposed to a range of political developments and consequent changes to the operating and regulatory environment.

We operate and may seek new opportunities in countries and regions where political, economic and social transition may take place. Political instability, changes to the regulatory environment or taxation, international sanctions, expropriation or nationalization of property, civil strife, strikes, insurrections, acts of terrorism and acts of war may disrupt or curtail our operations or development activities. These may in turn cause production to decline, limit our ability to pursue new opportunities, affect the recoverability of our assets or cause us to incur additional costs, particularly due to the long-term nature of many of our projects and significant capital expenditure required.

Rosneft investment our investment in Rosneft may be impacted by events in or relating to Russia and our ability to recognize our share of Rosneft s income, production and reserves may be adversely impacted.

Events in or relating to Russia, including further trade restrictions and other sanctions, could adversely impact our investment in Russia. To the extent we are unable in the future to exercise significant influence over our investment in Rosneft or pursue growth opportunities in Russia, our business and strategic objectives in Russia and our ability to recognize our share of Rosneft s income, production and reserves may be adversely impacted.

Liquidity, financial capacity and financial, including credit, exposure failure to work within our financial framework could impact our ability to operate and result in financial loss.

Failure to accurately forecast, manage or maintain sufficient liquidity and credit could impact our ability to operate and result in financial loss. Trade and other receivables, including overdue receivables, may not be recovered and a substantial and unexpected cash call or funding request could disrupt our financial framework or overwhelm our ability to meet our obligations.

An event such as a significant operational incident, legal proceedings or a geopolitical event in an area where we have significant activities, could reduce our credit ratings. This could potentially increase financing costs and limit access to financing or engagement in our trading activities on acceptable terms, which could put pressure on the group s liquidity. Credit rating downgrades could trigger a requirement for the company to review its funding arrangements with the BP pension trustees and may cause other impacts on financial performance. In the event of extended constraints on our ability to obtain financing, we could be required to reduce capital expenditure or increase asset disposals in order to provide additional liquidity. See Liquidity and capital resources on page 211 and Financial statements Note 27.

Joint arrangements« and contractors we may have limited control over the standards, operations and compliance of our partners, contractors and sub-contractors.

We conduct many of our activities through joint arrangements, associates« or with contractors and sub-contractors where we may have limited influence and control over the performance of such operations. Our partners and contractors are responsible for the adequacy of the resources and capabilities they bring to a project. If these are found to be lacking, there may be financial, operational or safety risks for BP. Should an incident occur in an operation that BP participates in, our partners and contractors may be unable or unwilling to fully compensate us against costs we may incur on their behalf or on behalf of the arrangement. Where we do not have operational control of a venture, we may still be pursued by regulators or claimants in the event of an incident.

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Digital infrastructure and cybersecurity breach of our digital security or failure of our digital infrastructure could damage our operations and our reputation.

A breach or failure of our digital infrastructure due to intentional actions such as attacks on our cybersecurity, negligence or other reasons, could seriously disrupt our operations and could result in the loss or misuse of data or sensitive information, injury to people, disruption to our business, harm to the environment or our assets, legal or regulatory breaches and potentially legal liability. These could result in significant costs or reputational consequences.

Climate change and carbon pricing public policies could increase costs and reduce future revenue and strategic growth opportunities.

Changes in laws, regulations and obligations relating to climate change could result in substantial capital expenditure, taxes and reduced profitability. In the future, these could potentially impact our upstream assets, revenue generation and strategic growth opportunities.

Competition inability to remain efficient, innovate and retain an appropriately skilled workforce could negatively impact delivery of our strategy in a highly competitive market.

Our strategic progress and performance could be impeded if we are unable to control our development and operating costs and margins, or to sustain, develop and operate a high-quality portfolio of assets efficiently. We could be adversely affected if competitors offer superior terms for access rights or licences, or if our innovation in areas such as exploration, production, refining or manufacturing lags the industry. Our performance could also be negatively impacted if we fail to protect our intellectual property.

Our industry faces increasing challenge to recruit and retain skilled and experienced people in the fields of science, technology, engineering and mathematics. Successful recruitment, development and retention of specialist staff is essential to our plans.

Crisis management and business continuity potential disruption to our business and operations could occur if we do not address an incident effectively.

Our business and operating activities could be disrupted if we do not respond, or are perceived not to respond, in an appropriate manner to any major crisis or if we are not able to restore or replace critical operational capacity.

Insurance our insurance strategy could expose the group to material uninsured losses.

BP generally purchases insurance only in situations where this is legally and contractually required. We typically bear losses as they arise rather than spreading them over time through insurance premiums. This means uninsured losses could have a material adverse effect on our financial position, particularly if they arise at a time when we are facing material costs as a result of a significant operational event which could put pressure on our liquidity and cash flows.

Safety and operational risks

Process safety, personal safety, and environmental risks we are exposed to a wide range of health, safety, security and environmental risks that could result in regulatory action, legal liability, increased costs, damage to our reputation and potentially denial of our licence to operate.

Technical integrity failure, natural disasters, human error and other adverse events or conditions could lead to loss of containment of hydrocarbons or other hazardous materials, as well as fires, explosions or other personal and process safety incidents, including when drilling wells, operating facilities and those associated with transportation by road, sea or pipeline.

There can be no certainty that our operating management system or other policies and procedures will adequately identify all process safety, personal safety and environmental risks or that all our operating activities will be conducted in conformance with these systems. See Safety on page 39.

Such events, including a marine incident, or inability to provide safe environments for our workforce and the public while at our facilities, premises or during transportation, could lead to injuries, loss of life or environmental damage. We could as a result face regulatory action and legal liability, including penalties and remediation obligations, increased costs and potentially denial of our licence to operate. Our activities are

sometimes conducted in hazardous, remote or environmentally sensitive locations, where the consequences of such events could be greater than in other locations.

Drilling and production challenging operational environments and other uncertainties can impact drilling and production activities.

Our activities require high levels of investment and are often conducted in extremely challenging environments which heighten the risks of technical integrity failure and the impact of natural disasters. The physical characteristic of an oil or natural gas field, and 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.

Security hostile acts against our staff and activities could cause harm to people and disrupt our operations.

Acts of terrorism, piracy, sabotage and similar activities directed against our operations and facilities, pipelines, transportation or digital infrastructure could cause harm to people and severely disrupt business and operations. Our activities could also be severely affected by conflict, civil strife or political unrest.

Product quality supplying customers with off-specification products could damage our reputation, lead to regulatory action and legal liability, and potentially impact our financial performance.

Failure to meet product quality standards could cause harm to people and the environment, damage our reputation, result in regulatory action and legal liability, and impact financial performance.

Compliance and control risks

US government settlements our settlements with legal and regulatory bodies in the US in respect of certain charges related to the Gulf of Mexico oil spill may expose us to further penalties, liabilities and private litigation or could result in suspension or debarment of certain BP entities.

Settlements with the US Department of Justice (DoJ) and the US Securities and Exchange Commission (SEC) impose significant compliance and remedial obligations on BP and its directors, officers and employees, including the appointment of an ethics monitor, a process safety monitor and an independent third-party auditor. Failure to comply with the terms of these settlements could result in further enforcement action by the DoJ and the SEC, expose us 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 reputation and financial performance. Failure to satisfy the requirements or comply with the terms of the administrative agreement with the US Environmental Protection Agency (EPA), under which BP agreed to a set of safety and operations, ethics and compliance and corporate governance requirements, could result in suspension or debarment of certain BP entities.

Regulation changes in the regulatory and legislative environment could increase the cost of compliance, affect our provisions and limit our access to new exploration opportunities.

Governments that award exploration and production interests may impose specific drilling obligations, environmental, health and safety controls, controls over the development and decommissioning of a field and possibly, nationalization, expropriation, cancellation or non-renewal of contract rights. Royalties and taxes tend to be high compared with those of other commercial activities, and in certain jurisdictions there is a degree of uncertainty relating to tax law interpretation and changes. Governments may change their fiscal and regulatory frameworks in response to public pressure on finances, resulting in increased amounts payable to them or their agencies.

Such factors could increase the cost of compliance, reduce our profitability 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, decommissioning, environmental and legal liabilities. Potential changes to pension or financial market regulation could also impact funding requirements of the group.

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Following the Gulf of Mexico oil spill, there have been cases of additional oversight and more stringent regulation of BP and other companies oil and gas activities in the US and elsewhere, particularly relating to environmental, health and safety controls and oversight of drilling operations, which could result in increased compliance costs. In addition, we may be subjected to a higher number of citations and level of fines imposed in relation to any alleged breaches of safety or environmental regulations, which could result in increased costs.

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

Incidents of ethical misconduct or non-compliance with applicable laws and regulations, including anti-bribery and corruption and anti-fraud laws, trade restrictions or other sanctions, or non-compliance with the recommendations of the ethics monitor appointed under the terms of the DoJ and EPA settlements, could damage our reputation, result in litigation, regulatory action and penalties.

Treasury and trading activities ineffective management of treasury and trading activities could lead to business disruption, financial loss, regulatory intervention or damage to our reputation.

We are subject to operational risk around our treasury and trading activities in financial and commodity markets, some of which are regulated. Failure to process, manage and monitor a large number of complex transactions across many markets and currencies while complying with all regulatory requirements could hinder profitable trading opportunities. There is a risk that a single trader or a group of traders could act outside of our delegations and controls, leading to regulatory intervention and resulting in financial loss and potentially damaging our reputation. See Financial statements Note 27.

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, including reserves estimates, relies on the integrity of systems and people. Failure to report data accurately and in compliance with applicable standards could result in regulatory action, legal liability and damage to our reputation. For a period of three years after the SEC settlement in December 2012, we are unable to rely on the US safe harbor provisions regarding forward-looking statements, which may expose us to future litigation and liabilities in connection with our public disclosures. See Legal proceedings on page 228.

The Strategic report was approved by the board and signed on its behalf by David J Jackson, company secretary on 3 March 2015.

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Board of directors

As at 3 March 2015

See BP s board governance principles related to director independence on page 239.

Carl-Henric Svanberg

Chairman

Chair of nomination and chairman s committees; attends Gulf of Mexico, SEEAC[a] and remuneration committees

Bob Dudley

Group chief executive

Paul Anderson

Independent non-executive director

Chair of the SEEAC; member of the chairman s, Gulf of Mexico and nomination committees

Alan Boeckmann

Independent non-executive director

Member of the chairman s, Gulf of Mexico and SEEAC committees; attends the remuneration committee

Admiral Frank Bowman

Independent non-executive director

Member of the chairman s, SEEAC and Gulf of Mexico committees

Antony Burgmans

Independent non-executive director

Chair of the remuneration committee; member of the chairman s, SEEAC and nomination committees

Cynthia Carroll

Independent non-executive director

Member of the chairman s, SEEAC and nomination committees

George David

Independent non-executive director

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

Ian Davis

Independent non-executive director

Chair of the Gulf of Mexico committee; member of the chairman s, nomination and remuneration committees

Professor Dame Ann Dowling

Independent non-executive director

Member of the chairman s, SEEAC and remuneration committees

Dr Brian Gilvary

Chief financial officer

Brendan Nelson

Independent non-executive director

Chair of the audit committee; member of the chairman s and nomination committees

Phuthuma Nhleko

Independent non-executive director

Andrew Shilston

Senior independent non-executive director

David Jackson

Company secretary

Member of the chairman s and audit committees	Member of the chairman s and audit committees; attends nomination committee	[a] Safety, ethics and environment assurance committee.

Carl-Henric Svanberg

Chairman

Tenure

Appointed 1 September 2009

Outside interests

Chairman of AB Volvo

Age 62 **Nationality** Swedish

Career

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

Carl-Henric 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, he was president and chief executive officer of Ericsson, also serving as the chairman of Sony Ericsson

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, Bob was executive assistant to the group chief executive, subsequently becoming group vice president for BP s renewables and alternative energy activities. In 2002, he became group vice president responsible for BP s upstream businesses in Russia, the Caspian region, Angola, Algeria and Egypt.

From 2003 to 2008, he was president and chief executive officer of TNK-BP. On his return to BP in 2009 he was appointed to the BP board and oversaw the group s activities in the Americas and Asia. Between 23 June and 30 September 2010, he served as the president and chief executive officer of BP s Gulf Coast

served as a non-executive director of BAE Systems PLC and on a number of boards in the US and Australia, and was also chief executive officer of Pan Energy Corp and chairman of Spectra Energy.

Relevant skills and experience

Paul Anderson has spent his career in the oil and gas industry working with global organizations. He brings the skills of an experienced chairman and chief executive and has played an important role, as chairman of the SEEAC since 2012, of continuing the board s focus on safety and on broader non-financial issues. His experience of business in the US and its regulatory environment has greatly assisted the work of the Gulf of Mexico committee.

Paul has continued to ensure that the SEEAC s activities are not limited to the UK by leading visits, in this year, to Baku and Brazil.

Alan Boeckmann

the engineering and contracting industry which was developed not only in the United States but also globally. He is an engineer and brings the skills of that profession to the SEEAC. Over his career he has been involved in remuneration matters and will join the remuneration committee after the 2015 AGM.

Admiral Frank Bowman

Independent non-executive director

Tenure

Appointed 8 November 2010

Outside interests

President of Strategic Decisions, LLC

Director of Morgan Stanley Mutual Funds

Director of Naval and Nuclear Technologies, LLP

Mobile Communications AB. He was a non-executive director of Ericsson between 2009 and 2012. He was appointed chairman and a member of the board of AB Volvo on 4 April 2012.

He is a member of the External Advisory Board of the Earth Institute at Columbia University and a member of the Advisory Board of Harvard Kennedy School. He is also the recipient of the King of Sweden s medal for his contribution to Swedish industry.

Relevant skills and experience

Carl-Henric Svanberg has, throughout his career, been involved with businesses with a global reach. He has done this as both a chairman and a chief executive officer. His experience is very broad which has assisted him in leading the board in the development of the group s strategy. He is focused on the development of the board as the long-term stewards of the company and ensuring the right combination of skills and diversity on the board to deliver that task.

Carl-Henric Svanberg s performance has been evaluated by the chairman s committee, led by Andrew Shilston.

Restoration Organization in the US. He was appointed a director of Rosneft in 2013 following BP s acquisition of a stake in Rosneft.

Relevant skills and experience

Bob Dudley has spent his entire career in the oil and gas industry. He has held senior management roles in Amoco and BP and has significant experience as the chief executive officer of TNK-BP.

Over the four years that he has been group chief executive, Bob has used these skills in leading BP s recovery. He initiated the 10-point plan, the main 2014 tasks of which have been completed. He has changed the way in which the group operates and focused its delivery on value not volume. He has reshaped the group through non-core asset divestment and has achieved a clear direction through a set of consistent values.

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

Independent non-executive director

Tenure

Appointed 24 July 2014

Outside interests

Non-executive director of Sempra Energy and Archer Daniels Midland

Board member and trustee of Eisenhower Medical Center in Rancho Mirage, California

Age 66 **Nationality** American

Career

Alan Boeckmann retired as non-executive chairman of Fluor Corporation in February 2012, ending a 35-year career with the company. Between 2002 and 2011, he held the post of chairman and chief executive officer, and was president and chief operating officer from 2001 to 2002. His tenure with the company included responsibility for global operations.

Age 70 **Nationality** American

Career

Frank L Bowman served for more than 38 years in the US Navy, rising to the rank of Admiral. He commanded the nuclear submarine *USS City of Corpus Christi* and the submarine tender *USS Holland*. After promotion to flag officer, he served on the joint staff as director of political-military affairs and as the chief of naval personnel. He then served over eight years as director of the Naval Nuclear Propulsion Program where he was responsible for the operations of more than one hundred reactors aboard the US navy s aircraft carriers and submarines. He holds two masters degrees in engineering from the Massachusetts Institute of Technology.

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

Bob Dudley

Group chief executive

Tenure

Appointed to the board 6 April 2009

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 the Emirates Foundation Board of Trustees

Age 59 **Nationality** American

Career

Bob Dudley became group chief executive on 1 October 2010.

Paul Anderson

Independent non-executive director

Tenure

Appointed 1 February 2010

Outside interests

No external appointments

Age 69 **Nationality** American

Career

Paul Anderson was formerly chief executive at BHP Billiton and at 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

As chairman and chief executive officer, he refocused the company on engineering, procurement, construction and maintenance services.

After graduating from the University of Arizona with a degree in electrical engineering, he joined Fluor in 1974 as an engineer and worked in a variety of domestic and international locations, including South Africa and Venezuela.

Alan was previously a non-executive director of BHP Billiton and the Burlington Santa Fe Corporation, and has served on the boards of the American Petroleum Institute, the National Petroleum Council and the advisory board of Southern Methodist University s Cox School of Business.

He led the formation of the World Economic Forum s Partnering Against Corruption initiative in 2004.

Relevant skills and experience

Knight Commander of the British Empire in 2005. He was elected to the US National Academy of Engineering in 2009.

Frank is a member of the CNA military advisory board and has participated in studies of climate change and its impact on national security. Additionally he was co-chair of a National Academies study investigating the implication of climate change for naval forces.

Relevant skills and experience

Frank Bowman has a deep knowledge of engineering coupled with exceptional experience in safety issues arising from his time with the US Navy and, later, the Nuclear Energy Institute. When coupled with his work on the BP Independent Safety Review Panel, Admiral Bowman has direct experience of BP s safety goals. In addition, the other roles in his career give him a broader perspective of systems and of people. He continues to make important contributions to the work of the SEEAC and the Gulf of Mexico committee.

Alan Boeckmann was asked to join the board because of his deep experience as a chairman and chief executive officer in

Antony Burgmans

Independent non-executive director

Tenure

Appointed 5 February 2004

Outside interests

Member of the supervisory board of SHV Holdings N.V.

Chairman of the supervisory board of TNT Express

Chairman of Akzo Nobel N.V.

Age 68 **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 joined the board of Unilever, becoming business group president, ice cream and

extractive industries. This has required deep strategic and operational involvement. In leading these businesses a high level of interaction with governments, the media, special interest groups and other stakeholders has been needed.

Cynthia began her career as a petroleum geologist with Amoco Production company in Denver, Colorado, after completing a masters degree in geology. In 1989, she 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 skills and experience

Ian Davis

Independent non-executive director

Tenure

Appointed 2 April 2010

Outside interests

Chairman of Rolls-Royce Holdings plc

Non-executive member of the UK s Cabinet Office

Non-executive director of Johnson & Johnson, Inc.

Senior adviser to Apax Partners LLP

Age 63 **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

Turbomachinery in the Department of Engineering in 2002. She was appointed the UK lead of the Silent Aircraft Initiative in 2003, a collaboration between researchers at Cambridge and MIT. She was head of the Department of Engineering at the University of Cambridge from 2009 to 2014. 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 was elected President of the Royal Academy of Engineering in September 2014.

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.

Relevant skills and experience

Antony Burgmans is an experienced chairman and chief executive who has served on the BP board for over 11 years. He spent his executive career at Unilever where he developed skills in production, distribution and marketing. His experience of consumer facing business has meant that he has been able to provide the board with deep insight in the fields of reputation, brand, culture and values. He was asked to remain on the board until 2016 in the light of rapid board turnover in 2010 and 2011. Antony remains fully independent.

Antony has now led the remuneration committee for five years and has detailed and regular dialogue with shareholders on remuneration

Cynthia Carroll is an experienced former chief executive who has spent all of her career in the extractive industries, having trained as a petroleum geologist. Cynthia has been a leader in working to enhance safety in the mining industry. She has also made a strong contribution to the work of the SEEAC and notably to the nomination committee.

George David

Independent non-executive director

Tenure

Appointed 11 February 2008

Outside interests

Vice-chairman of the Peterson Institute for International Economics

Age 72 **Nationality** American

Career

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 in July 2010.

Relevant skills and experience

Ian Davis brings the skills of a managing director and significant financial and strategic experience to the board. He has worked with and advised global organizations and companies in the oil and gas industry. His work in the public sector and with the Cabinet Office gives him a unique perspective on government affairs.

He has chaired the Gulf of Mexico committee since its formation and has led the board s oversight of the response in the Gulf and guided the board s consideration of the various legal issues which continue to arise following the Deepwater Horizon accident. He has been an active member of the remuneration committee.

Relevant skills and experience

Dame Ann has a strong engineering background, not only in the academic world but also in its practical application in business. She has led the department of engineering at Cambridge which is one of the leading centres for engineering research worldwide. This has been recognized by her appointment as President of the Royal Academy of Engineering. She chairs the BP technology advisory council which aims to provide challenge and direction to the work in the field of technology throughout the group. Dame Ann is a member of the SEEAC and, having joined the remuneration committee in 2012, will take its chair when Antony Burgmans stands down during 2015.

Dr Brian Gilvary

Chief financial officer

Tenure

Appointed to the board 1 January 2012

Outside interests

matters. He will hand the chair of the remuneration committee to Professor Dame Ann Dowling in 2015, and, having previously led the evaluation of the chairman, he handed this task to Andrew Shilston this year in anticipation of standing down at the 2016 AGM.

Cynthia Carroll

Independent non-executive director

Tenure

Appointed 6 June 2007

Outside interests

Non-executive director of Hitachi Ltd.

Age 58 **Nationality** American

Career

Cynthia Carroll has led multiple large complex global businesses in the

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 and served as its chief executive officer from 1994 until 2008 and as chairman from 1997 until his retirement in 2009.

Relevant skills and experience

George David has substantial business and financial experience through his long career with UTC, a business with significant reliance on safety and technology. His time as a chairman and a chief executive officer has been valuable in enabling him to engage in the complexities of global business. He has previously chaired BP s technology advisory council and has brought insights from that task to the board.

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

Professor Dame Ann Dowling

Independent non-executive director

Tenure

Appointed 3 February 2012

Outside interests

Professor of Mechanical Engineering at the University of Cambridge
President of the Royal Academy of Engineering

Member of the Prime Minister s Council for Science and Technology

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

Age 62 **Nationality** British

Career

Dame Ann Dowling was appointed a Professor of Mechanical Engineering in the Department of

Visiting professor at Manchester University

External advisor to director general (spending and finance), HM Treasury Financial Management Review Board

Age 53 **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. 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.

Engineering at the University of Cambridge in 1993. She became Head of the Division of Energy, Fluid Mechanics and

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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.

Relevant skills and experience

Dr Brian Gilvary has spent his entire career at BP. He has a strong knowledge of finance and trading and a deep understanding of BP s assets and businesses. Having worked in both Upstream and Downstream, he also has very broad experience of the business as a whole.

Brian has consistently worked to further strengthen the finance function and has continued to develop the company s engagement with shareholders.

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

Brendan Nelson

Independent non-executive director

Phuthuma Nhleko

Independent non-executive director

Tenure

Appointed 1 February 2011

Outside interests

Non-executive director of Anglo American plc

Non-executive director and chairman of MTN Group Ltd

Chairman of the Pembani Group

Age 54 **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

He has served as a non-executive director on the board of Cairn Energy plc where he chaired the audit committee.

Relevant skills and experience

Andrew Shilston has had a long career in finance in the oil and gas industry and more generally. His knowledge and experience as a chief financial officer, firstly in Enterprise Oil and then Rolls-Royce, makes him well suited to be a member of BP s audit committee. This is complemented by his experience as the chair of the audit committee at Cairn Energy.

Andrew has very broad experience of the oil and gas industry which has assisted the board in its work in overseeing the group s strategy and in particular the evaluation of capital projects.

As senior independent director he has contributed to the work of the nomination committee. He has also overseen the evaluation of the chairman in 2014 and will lead the external evaluation of the

The ages of the board are correct as at 3 March 2015.

Tenure

Appointed 8 November 2010

Outside interests

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

Member of the Financial Reporting Council Monitoring Committee

Age 65 **Nationality** British

Career

Brendan Nelson is a chartered accountant. He was made a partner of KPMG in 1984 and 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 for six years as a member of the Financial Services Practitioner Panel and in 2013 was the president of the Institute of Chartered

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 and became chairman. 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 skills and experience

Phuthuma Nhleko s background in engineering and his broad experience as a chief executive of a multinational company enables him to make a broad contribution to the board. This is particularly so in the areas of emerging market economies and the evolution of the group s

board in 2015.

David Jackson

Company secretary

Tenure

Appointed 2003

David Jackson, a solicitor, is a director of BP Pension Trustees Limited.

Accountants of Scotland.

Relevant skills and experience

Brendan Nelson has had a long career in finance and auditing, particularly in the areas of financial services and trading. During his career he has also had management experience at a very senior level. He is well qualified to chair the audit committee and to act as its financial expert. As chair of the audit committee he has focused particularly on the oversight of the group s trading operations.

All of this is complemented by his broader business experience and his role as the chair of the audit committee of a major bank.

strategy. His financial and commercial experience is also very relevant to his work on the audit committee.

Andrew Shilston

Senior independent non-executive director

Tenure

Appointed 1 January 2012

Outside interests

Non-executive director of Circle Holdings plc

Chairman of the Morgan Advanced Materials plc

Age 59 **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.

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Executive team

As at 3 March 2015

Rupert Bondy

Current position

Group general counsel

Executive team tenure

Appointed 1 May 2008

Outside interests

Non-executive director, Indivior PLC

Age 53 **Nationality** British

Career

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

Career

Tufan Erginbilgic was appointed chief executive, Downstream on 1 October 2014.

Prior to this, Tufan was the chief operating officer of the fuels business, accountable for BP s fuels value chains worldwide, the global fuels businesses and the refining, sales and commercial optimization functions for fuels. Tufan joined Mobil in 1990 and BP in 1997 and has held a wide variety of roles in refining and marketing in Turkey, various European countries and the UK. In 2004 he became head of the European fuels business. Tufan took up leadership of BP s lubricant business in 2006 before moving to head the group chief executive s office. In 2009 he became chief operating officer for the eastern hemisphere fuels value chains and lubricants businesses.

Bob Fryar

Current position

Executive vice president, safety and operational risk

Trinidad, including chief operating officer for Atlantic LNG, and vice president of operations. Bob has also served in a variety of engineering and management positions in onshore US and deepwater Gulf of Mexico.

Andy Hopwood

Current position

Chief operating officer, strategy and regions, Upstream

Executive team tenure

Appointed 1 November 2010

Outside interests

President TOC-Rocky Mountains Inc.

Vice president BP Corporation North America Inc.

Age 57 **Nationality** British

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 55 **Nationality** American

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, 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 in May 2008.

Tufan Erginbilgic

Current position

Chief executive, Downstream

Executive team tenure

Executive team tenure

Appointed 1 October 2010

Outside interests

No external appointments

Age 51 Nationality American

Career

Bob Fryar is responsible for strengthening safety, operational risk management and the systematic management of operations across the BP group. He is group head of safety and operational risk, with accountability for group-level disciplines including engineering, health, safety, security, and the environment. In this capacity, he looks after the group-wide operating management system implementation and capability programmes.

Bob has 29 years experience in the oil and gas industry, having joined Amoco Production Company in 1985. Between 2010 and 2013, Bob was executive vice president of the

Career

Andy Hopwood is responsible for BP s upstream strategy, portfolio, and leadership of its global regional presidents.

Andy joined BP in 1980, spending his first 10 years in operations in the North Sea, Wytch Farm, and Indonesia. In 1989 Andy joined the corporate planning team formulating BP s upstream strategy, and subsequent portfolio rationalization. Andy held commercial leadership positions in Mexico and Venezuela, before becoming the Upstream s planning manager. Following the BP-Amoco merger, Andy spent time leading BP s businesses in Azerbaijan, Trinidad & Tobago, and onshore North America. In 2009, he joined the Upstream executive team as head of portfolio and technology and in 2010 was appointed executive vice president, exploration and production.

Career

Katrina Landis is responsible for BP s integrated supply and trading activities, renewable energy activities, 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. In May 2013, she became executive vice president, corporate business activities. Since mid-2010 she has served as an independent director of Alstom SA, a world leader in transport infrastructure, power generation, and transmission, and is a founding member of Alstom s ethics, compliance and sustainability committee.

Appointed 1 October 2014

Outside interests

Independent non-executive director of GKN plc.

Age 55 **Nationality** British and Turkish

production division and was accountable for safe and compliant exploration and production operations and stewardship of resources across all regions. Prior to this, Bob was chief executive of BP Angola and also held several management positions in

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Bernard Looney

Current position

Chief operating officer, production

Executive team tenure

Appointed 1 November 2010

Outside interests

Member of the Stanford University Graduate School of Business Advisory Council

Fellow of the Energy Institute

Age 44 **Nationality** Irish

Career

Bernard Looney is responsible for BP s operated production, with specific accountability for drilling, operations, engineering, procurement and supply chain management, and 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 responsibility for drilling operations on Thunder Horse in the deepwater Gulf of Mexico. In 2005 he became senior vice president for 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. At the same time, Bernard became a member of the Oil & Gas UK Board the North Sea oil and gas trade association. He became co-chair in mid-2010. Bernard became executive vice president, developments, in October 2010 and took up his current role in February 2013.

Lamar McKay

Current position

Chief executive, Upstream

Executive team tenure

Appointed 16 June 2008

Outside interests

Member of Mississippi State University Dean s Advisory Council

Age 56 **Nationality** American

Career

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

Lamar started his career in 1980 with Amoco and held a range of technical and leadership roles.

During 1998 to 2000, he worked on the BP-Amoco merger and served as head of strategy and planning for the exploration and production business. In 2000 he became business unit leader for the central North Sea. In 2001 he became chief of staff for exploration and production, and subsequently for BP s deputy group chief executive. Lamar became group vice president, Russia and Kazakhstan in 2003. He served as a member of the board of directors of TNK-BP between February 2004 and May 2007. In 2007 he was appointed executive vice president, BP America. In 2008 he became executive vice president, special projects where he led BP s efforts to restructure the governance framework for TNK-BP. In 2009 Lamar was appointed chairman and president of BP America, serving as BP s chief representative in the US. In January 2013, he became chief executive, Upstream.

Dev Sanyal

Current position

Executive vice president, strategy and regions

Executive team tenure

Appointed 1 January 2012

Outside interests

Independent non-executive director, Man Group plc.

Member, Accenture Global Energy Board

Member of Board of Advisors of the Fletcher School of Law and Diplomacy

Age 49 **Nationality** British and Indian

Career

Dev Sanyal is responsible for Europe, Asia, strategy and long-term planning, risk management, 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. He moved to London as chief of staff of BP s worldwide downstream

businesses in 2002. In November 2003 he was appointed chief executive officer of Air BP international. 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 was accountable for the group s aluminium interests.

Helmut Schuster

Current position

Executive vice president, group human resources director

Executive team tenure

Appointed 1 March 2011

Outside interests

Non-executive director of Ivoclar Vivadent AG

Age 54 **Nationality** Austrian

Career

Helmut Schuster became group human resources director in March 2011. In this role he is accountable 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 within the organization. He has worked in BP offices in the US, the UK and continental Europe and within most parts of refining, marketing, trading and gas and power. Before taking on his current role, his responsibilities as a vice president, human resources included the refining and marketing segment of BP, and corporate and functions. That role saw him leading the people agenda for roughly 60,000 people across the globe that includes businesses such as petrochemicals, fuels value chains, lubricants and functional experts across the group.

The executive team represents the principal executive leadership of the BP group. Its members include BP s executive directors (Bob Dudley and Dr Brian Gilvary whose biographies appear on pages 52-55) and the senior management listed left.

The ages of the executive team are correct as at 3 March 2015.

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Governance overview

Introduction from the chairman

2014 was another active year for the board as we continued to work with Bob Dudley and his team in reshaping the way that BP operates.

Once again, I have been impressed by the time and commitment given by my board colleagues. We have built on the progress made in 2013 in developing how the board works in supporting and challenging executive management. We have had the benefit of being a settled group for several years now and I believe that this allows us to spend our time wisely. Later in this report there is a breakdown of our activities. I would, however, like to highlight several areas.

The 10-point plan set the direction of travel for the group through to 2014. We worked through the year with executive management to determine our strategic direction for 2015 and beyond. To do this, we regularly reflected on the impact of economics and geopolitics both in the world and the markets in which we operate.

This has particularly been the case as the oil price fell during the last quarter of the year and action was needed to reset the business to a lower-price environment.

During the year, we reviewed and enhanced the regular information which comes to the board. This is in response to feedback from directors which came from our 2013 board evaluation.

We also considered, in some depth, the manner in which the remuneration committee operates. We have adopted a revised set of tasks for the committee which reflect the need to balance development and implementation of the remuneration policy for the directors while overseeing the approach to reward for executives below the board.

BP, with input from board members, has revised its code of conduct with the aim of simplifying and clarifying its requirements without weakening their effect. As a board, we are committed to BP s values and the code, and have received training on its application.

In 2014 the UK Corporate Governance Code was revised. We have taken this into account at the board and in the committees whose work it impacts. There is particular focus on how risk is governed and managed. As a result there is much for us to consider here and we will be reviewing our systems ahead of its implementation in 2015.

The nomination committee has continued to assess the mix of the skills and experience on the board, in particular for the future, and in line with our aspiration for diversity. Your board has a diverse membership and we continue to work to increase its diversity. As I have previously commented, while candidates can be identified, it is often the case that the timing of appointments is dependent on those candidates becoming free from current commitments. You should expect us to make progress in the current year.

Finally, we have again this year, considered whether all our narrative reporting is fair, balanced and understandable . We have applied the process adopted last year and concluded that this report meets that test.

I believe that the system of governance used by the board has assisted it to meet the challenges of past years and will do so in the future.

Carl-Henric Svanberg

Chairman

Board diversity

BP recognizes the importance of diversity, including gender diversity, at the board and all levels of the group. BP is committed to increasing diversity across its operations and has in place a wide range of activities to support the development and promotion of talented individuals, regardless of gender and ethnic background.

The board operates a policy which aims to promote diversity in its composition. 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.

Implementation of this policy is monitored through agreed metrics. During its annual evaluation, the board considered diversity as part of the 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 and has an aspiration to increase this to 25% by the end of 2015. At the end of 2014 there were two female directors on the board. The nomination committee is actively considering diverse candidates as part of its wider search for board candidates and it is anticipated that an appointment is likely to be made in 2015.

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Board and committee attendance in 2014

	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	10	10									6[c]	6	5c	5
Paul Anderson[1]	10	10			7[c]	7			11	10	6	6	5	5
Alan Boeckmann	4	4			2	2			5	5			2	2
Frank Bowman	10	10			7	7			11	11			5	5
Antony Burgmans[2]	10	7			7	7	5[c]	5			6	6	5	4
Cynthia Carroll[3]	10	9			7	7					6	6	5	5
George David[4]	10	10	13	12			5	5	11	11			5	5
Ian Davis	10	10					5	5	11[c]	11	6	6	5	5
Ann Dowling	10	10			7	7	5	5					5	5
Brendan Nelson	10	10	13[c]	13							6	6	5	5
Phuthuma Nhleko[5]	10	10	13	12									5	5
Andrew Shilston[6]	10	9	13	12									5	5
Executive directors														
Bob Dudley	10	9												
Iain Conn	9	9												
Brian Gilvary	10	10												

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 attended all scheduled Gulf of Mexico committee meetings in 2014; however he was unable to attend the meeting on 15 September that was called at short notice due to long-standing travel arrangements.

[2] Antony Burgmans was unable to attend the board teleconference scheduled at short notice on 5 September 2014 due to a prior commitment. He was unable to attend the telephone board meeting on 27 October 2014 for health reasons and the board and chairman s committee meeting on 4 December 2014 due to a conflict with other board meetings on the same day.

[3] Cynthia Carroll was unable to attend the telephone board meeting on 27 October 2014 due to a conflicting board meeting.

[4] George David was unable to attend the telephone audit committee meeting on 26 February 2014 due to a clash with travel arrangements.

[5] Phuthuma Nhleko was unable to attend the telephone audit committee on 24 April due to a clash with the AGM of another company.

[6] Andrew Shilston attended all scheduled board and audit committee meetings in 2014; however he was unable to attend the board and audit teleconferences scheduled at short notice on 5 September 2014 due a prior overseas commitment.

How the board works

Board governance in BP

The board operates within a system of governance that is set out in the BP board governance principles. These principles 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. See *bp.com/governance* for the board governance principles.

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 principal risks and uncertainties 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.

The board seeks to set the tone from the top for BP by working with management to agree the company values and considering specific issues including health, safety, the environment and reputation.

Board composition

On 1 January 2015 the board had 14 directors the chairman, two executive directors and 11 independent, non-executive directors (NEDs).

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 pages 56-57.

The senior independent director

Andrew Shilston

Is available to shareholders if they have concerns that cannot be addressed through normal channels.

During 2014 Antony Burgmans, BP s longest serving non-executive director, has acted as an internal sounding board for the chairman and served as an intermediary for the other directors with the chairman when necessary. He has also led the chairman s evaluation. From the 2015 AGM, Andrew Shilston will assume these tasks as part of his role as senior independent director.

Neither the chairman nor the senior independent director is employed as an executive of the group.

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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, letters of appointment for NEDs do not set a fixed time commitment. 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 BP to perform their duties effectively and that they will make themselves available for all regular and ad-hoc meetings.

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 72).

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. It is the view of the board that all non-executive directors, with the exception of the chairman, are independent. See page 239 for a description of BP s board governance principles relating to director independence.

Antony Burgmans joined the board in February 2004 and by the 2015 AGM will have served 11 years as a director. In 2012, the board asked him to remain as a director until the 2016 AGM. The board continues to consider that his experience as the longest serving board member provides valuable insight, knowledge and continuity, that he continues to meet its 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 hold other external appointments. The nomination committee keeps the other interests of the NEDs under review to ensure that the effectiveness of the board is not compromised.

Succession

Alan Boeckmann joined the board in July 2014 as a non-executive director. He is a member of the Gulf of Mexico and the safety, ethics and environment assurance committees and attends the remuneration committee.

Iain Conn, chief executive of BP s Downstream segment, retired from the board on 31 December 2014.

At BP s AGM in 2015, George David will retire from the board following seven years service as a non-executive director.

Professor Dame Ann Dowling will take the chair of the remuneration committee when Antony Burgmans stands down in 2015.

Andrew Shilston and Alan Boeckmann will join the remuneration committee after the 2015 annual general meeting.

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. At every meeting, the board receives reports from the chair of each committee that has met since the last meeting. The main areas of focus by the board during 2014 are shown below.

Board activities

Risk and assurance

During the year the board, either directly or 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 was also assessed (see Internal Control Revised Guidance for Directors (Turnbull) on page 63).

The annual plan, group risk reviews and strategy are central to BP s risk management programme. They provide a framework by which the board can consider principal 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 the audit, SEEAC and Gulf of Mexico committees) monitored the group risks which were allocated following the board s review of the annual plan at the end of 2013.

Those group risks reviewed by the board during 2014 included risks associated with the delivery of BP s 10-point plan and geopolitical risk associated with BP s operations around the world. 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 board s monitoring committees (the audit, SEEAC 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 pages 64-71.

For 2015, the group risks allocated for review by the board include geopolitical risk and the delivery of major projects«, particularly in the Upstream. Further information on BP s system of risk management is outlined in Our management of risk on page 46.

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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 field visits to operations. The induction also covers governance, duties of directors, the work of the board committees generally and specifically the committees that a director will join.

To help develop an understanding of BP s business, the board continues to build its knowledge through briefings and field visits. In 2014 the board received training on BP s code of conduct and briefings on key business developments and changes to the UK Corporate Governance Code. The board met local management and external stakeholders at its board meetings in Istanbul and Chicago.

Non-executive directors are expected to attend at least one field visit per year. In 2014 the board visited the Whiting refinery in the US and members of the SEEAC visited BP s operations in Baku and Brazil. After each visit, the board or appropriate committee was briefed on the impressions gained by the directors during the visit.

Board evaluation

Each year BP undertakes a review of the board, its committees and individual directors. The chairman s performance is evaluated by the chairman s committee.

In 2014, an internally designed board evaluation for the board and the committees was carried out using a questionnaire prepared by an external facilitator (Lintstock). The evaluation tested key areas of the board s work including strategy, business performance, risk and governance processes. The output of the committee reviews were discussed individually at each committee meeting in December 2014. The output of the board review was used as the basis for one-to-one interviews between each director and the chairman. Results of the board evaluation and feedback from these interviews were discussed by the board in January 2015.

Key conclusions from the evaluation

The evaluation, which considered the work of the board and its committees, concluded that the processes of the board had worked well. The evaluation focused on how the board would continue to ensure that it was discussing the right issues and that, overall the board was adding value.

Reports from the business and on major projects were in very good shape. On the rapidly shifting economic and geopolitical climate, the board was keen to ensure that it manages its time to allow appropriate levels of discussion. The need to balance its monitoring activities with discussion on strategic matters was recognized and ought to be continually borne in mind. The future role of technology in delivering BP s strategy was highlighted.

Follow up from our previous evaluation

Following the 2013 evaluation, more agenda time was allocated to the development of strategy and governance around capital projects, resulting in the creation of a regular performance report on the group s major projects. The board also had a detailed briefing on the group s view on long-term technology trends and examined organizational capability, including diversity and inclusion, at one of its strategic days.

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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 those directors who met with shareholders over the year.

Shareholder engagement cycle 2014

January	g	*BP Energy Outlook 2035* presentation
February	g	Fourth quarter results
	g	Investor roadshows with executive management
March	g	Strategy update presentation to investors
	g	Chairman and board committee chairs meeting
	g	Engagement on remuneration and governance issues
	g	UKSA private shareholders meeting
	g	SRI updates unconventional gas and hydraulic fracturing; and oil sands
	g	SRI roadshow on *BP Sustainability Review 2013*
April	g	US legal issues conference call
	g	Annual General Meeting
	g	First quarter results
June	g	Launch of *BP Statistical Review of World Energy*
July	g	Second quarter results
	g	Publication of the BP proposition on *bp.com*
	g	Investor roadshows with the group CEO and CFO
August	g	Engagement with UKSA private shareholder panel on BP s 2013 financial reports
September	g	US legal issues conference call
	g	Oil and gas sector conferences
October	g	Third quarter results
December	g	Engagement on remuneration
	g	Group SRI meeting
	g	Upstream strategy presentation

Institutional investors

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 audit and remuneration committees held individual investor meetings to discuss strategy, the board s view on BP s performance, governance, audit and remuneration. An annual investor event was held in March 2014 with the chairman and all the board committee chairs. 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.

In December the chairman and members of the executive team met with socially responsible investors as part of BP s annual SRI meeting. The meeting examined a number of operational and strategic issues, including how the board looks at risk and strategy, *BP s Energy Outlook 2035*, how the company approaches operational risk, upstream contractor management, technology and BP s portfolio.

See *bp.com/investors* to download materials from investor presentations, including the group s financial results and information on the work of the board and its committees.

Private investors

BP held a further event for private investors in conjunction with the UK Shareholders Association (UKSA) in 2014. The chairman and head of investor relations made presentations on BP s annual results, strategy and the work of the board. The shareholders asked questions on BP s activities. Later in the year, the UKSA met with the company to give feedback on the *BP Strategic Report 2013*.

AGM

Voting levels decreased slightly in 2014 to 63.13% (of issued share capital, including votes cast as withheld), compared to 64.24% in 2013 and 63.24% in 2012. Each year the board receives a report after the AGM giving a breakdown of the votes and investor feedback on their voting decisions for the meeting to inform the board on any issues arising.

UK Corporate Governance Code compliance

BP complied throughout 2014 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).

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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, with one meeting held jointly with the main board. Between meetings IAB members remain on hand to provide advice and counsel when needed.

The IAB is chaired by BP s previous chairman, Peter Sutherland. Its membership in 2014 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 emerging geopolitical issues which could impact BP s business, developments in Russia, the Middle East and North Africa, the liberalization of Mexico s oil and gas sector and the US mid-term election cycle.

Internal Control Revised Guidance for Directors (Turnbull)

In discharging its responsibility for the company s risk management and internal control systems under the UK Corporate Governance Code, the board, through its governance principles, requires the group chief executive to operate with a comprehensive system of controls and internal audit to identify and manage the risks that are material to BP. The governance principles are reviewed periodically by the board and are consistent with the requirements of the UK Corporate Governance Code including principle C.2 (risk management and internal control).

The board has an established process by which the effectiveness of the system of internal control (which includes the risk management system) is reviewed as required by provision C.2.1 of the UK Corporate Governance Code. This process enables the board and its committees to consider the system of internal control being operated for managing significant risks, including strategic, safety and operational and compliance and control risks, throughout the year. Material joint ventures« and associates« have not been dealt with as part of the group in this process.

As part of this process, the board and the audit, Gulf of Mexico and safety, ethics and environment assurance committees requested, received and reviewed reports from executive management, including management of the business segments, 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 2014 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 2015 reviewed a report from the group head of audit as part of the board s annual review of the risk management and internal control systems. The report described the annual summary of group 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, group head of audit 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.

« Defined on page 252.

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Committee reports

Audit committee

Chairman s introduction

The work of the audit committee in 2014 remained focused on the appropriateness of BP s financial reporting and accounting judgements, the review of key group-level risks and the rigour of BP s audit processes, system of internal control and risk management. A number of key topics have remained core to the committee s agenda, including regular assessment of the group s financial responsibilities arising from the Deepwater Horizon accident and judgement on whether the group has maintained significant influence over Rosneft.

Outside these core areas, the committee undertook detailed reviews of key areas of BP s business, most notably in trading where the committee visited the trading floors in London and Chicago. This allowed the committee to see the role trading plays in the group s broader business and its system of governance, control, risk and compliance. Over the year, formal business of the committee was supplemented by private meetings with key constituents. These include BP s group audit function, the group ethics and compliance officer and the external auditor. I believe the background and experience of 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 system of internal control 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, and is chairman of the group audit committee of The Royal Bank of Scotland Group plc, and a member of the Financial Reporting Council Monitoring Committee. He was president of the Institute of Chartered Accountants of Scotland in 2013. 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 representatives of the external auditor, who also meet with the committee chair on a regular basis outside the meetings.

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 director responsibilities for assurance over joint ventures, trends and developments in the use of third-party agents and developments in global accounting standards.

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 accounting policies and judgements.

In conjunction with the SEEAC, the committee examined whether the *BP Annual Report and Form 20-F 2014* was fair, balanced and understandable and provided the information necessary for shareholders to assess the group s performance, business model and strategy.

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Accounting judgements and estimates

Areas of significant judgement considered by the committee during the year and how these were addressed included:

	Key issues/judgements in financial reporting	Audit committee review
Accounting for 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, on an ongoing basis in assessing whether there have been any changes in the level of control.	The committee continued to review the accounting for BP s investment in Rosneft including the assessment of significant influence in light of developments during the year, such as the imposition of US and EU sanctions.
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, including the treatment of certain intangible assets. The committee considered the judgements made in assessing the exploration write-offs recorded during the year. It received a briefing on the measurement of reserves and also examined the group s oil and gas reserves disclosures that appear in this *BP Annual Report and Form 20-F 2014*.
Recoverability of asset carrying values	Determining 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, particularly in light of the decline in prices in the latter part of the year. The committee considered the judgements made in assessing the existence of indicators of impairment of assets as well as the significant estimates made in the measurement of the impairment losses recognized. The committee also continued to discuss periodically with management the recoverability of overdue receivables.
Provisions and contingencies	The group holds provisions for the future decommissioning of oil and natural gas	The committee received briefings on the group s decommissioning, environmental

	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.	remediation and litigation provisioning, including key assumptions used, discount rates and the movement in provisions over time.
Gulf of Mexico oil spill	Judgement was applied during the year around 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, external auditors and external counsel, including as part of the review of BP s stock exchange announcement at each quarter end. The committee examined developments relating to US court rulings (including Clean Water Act penalties, business and economic loss settlement payments and natural resource damages) and monitored legal developments while considering the impact 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.
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.

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Audit committee focus in 2014

* Undertaken jointly with the SEEAC.

Risk reviews

The group risks allocated to the audit committee for monitoring in 2014 included those associated with trading activities, compliance with applicable laws and regulations and security threats against BP s digital infrastructure. The committee held in-depth reviews of these group risks over the year. It also examined the group s governance of the tax function and its approach to tax planning and reviewed how risk is assessed and considered when evaluating BP s capital investment 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 reviewed 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 significant allegations and investigations and on key ethics and compliance issues. Further joint meetings were held with the SEEAC to discuss the annual certification report of compliance with the BP code of conduct and the role and remit of the newly formed business integrity function. The two committees also met to discuss the group audit and ethics and compliance programmes for 2014. The committee held a private meeting with the group ethics and compliance officer during the year.

External audit

The external auditors started the annual cycle with their audit strategy which identified key risks to be monitored during the year including the provisions and contingencies related to the Gulf of Mexico oil spill, the impact of the estimation of the quantity of oil and gas reserves and resources on impairment testing, depreciation, depletion and amortization and decommissioning provisions, unauthorized trading activity and BP s ability to maintain significant influence over Rosneft and consequently our ability to recognize our share of Rosneft s income, production and reserves. The committee received updates during the year on the audit process, including how the auditors had challenged the group s assumptions on these issues.

The audit committee reviews the fee structure, resourcing and terms of engagement for the external auditor annually. Fees paid to the external auditor for the year were $53 million, of which 8% was for non-assurance work (see Financial statements Note 34). Non-audit or non-audit related assurance fees were $5 million (2013 $5 million). Non-audit or non-audit related assurance services consisted of tax compliance services, tax advisory services and services relating to corporate finance transactions. The audit committee is satisfied that this level of fee is appropriate in respect of the audit services provided and that an effective audit can be conducted for this fee.

The effectiveness of the audit process was evaluated through a survey of the committee and those impacted by the audit. It used a set of criteria to measure the auditors performance against the quality commitment set out in their annual audit plan. This related to both the quality of opinion and of service. This included the robustness of the audit process, independence and objectivity, quality of delivery, quality of people and service and value added advice. The 2014 evaluation concluded that there was a good quality audit process and that the external auditors were regarded as technically knowledgeable and unafraid to challenge and intervene where necessary. Areas of suggested focus for the auditors included audit team turnover and the identification of risk areas for audit focus. 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 its 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. It 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 taking into account the UK Corporate Governance Code, the EU Audit Regulation 2014 and the Statutory Audit Service Order 2014, issued by the UK Competitions and Markets Authority. Having considered the impact of these regimes, the committee concluded that the best interests of the group and its shareholders would be served by utilizing the transition arrangements outlined by the Financial Reporting Council in relation to the governance code 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.

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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 auditor is only considered for permitted non-audit services when its expertise and experience of the company is important. A two-tier system operates for approval of audit-related and non-audit work. 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 a case-by-case 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 2014 the committee used an online survey which examined governance issues such as committee processes and support, the work of the committee and priorities for change.

Areas of focus for 2015 arising from the evaluation included the inclusion of broader segment and business reviews, undertaking more deep dive reviews and suggestions for further committee training.

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.

g Tax performance advisory.

Other services

g Workshops, seminars and training on an arm s length basis.

g Assistance on non-financial regulatory requirements.

g Provision of independent third-party audit on BP s Conflict Minerals Report.

Non-permitted services

SEC principles of auditor independence

g Bookkeeping/other services related to financial records.
g Financial information systems design and implementation.
g Appraisal, valuation, fairness opinions, contribution in-kind.
g Actuarial services.

g Internal audit outsourcing.
g Management functions.
g HR functions.
g Broker-dealer, investment advisor, banking services.
g Legal services.
g Expert services unrelated to audit.

Public Company Accounting Oversight Board (PCAOB) ethics and independence rules

g Contingent fees.

g Confidential or aggressive tax position transactions.

g Tax services for persons in financial reporting oversight roles.

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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 included the committee receiving specific reports on BP s management of high priority risks in marine, wells, pipelines, facilities and major security incidents. The committee also undertook a number of field visits as well as maintained its schedule of regular meetings with executive management.

We continued to receive regular reports from the independent experts that we have engaged in 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.

We were also very pleased to welcome Alan Boeckmann to the committee in September. Alan brings valuable experience and insight from his many years at Fluor.

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 as well as cross-business information from the functions. These include, but are not limited to, the safety and operational risk (S&OR) 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 six times in 2014, 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 63). 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 the SEEAC meetings were attended by the group chief executive, the executive vice president for safety and operational risk and the general auditor or his delegate. The external auditor attended some of the meetings (and was briefed on the other meetings by the chair and secretary to the committee), as did the group general counsel and group ethics and compliance officer. 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
Alan Boeckmann	Member since September 2014

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 marine, wells, pipelines, facilities and major security incidents. The committee reviewed these risks, and risk management and mitigation, in depth with 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. We were pleased that Mr Sandlin agreed, at the committee s request, to extend his engagement to the summer of 2016. He reported twice directly to the SEEAC in 2014, and presented detailed reports on his work, including reporting on a number of visits made to group operations around the world. He also reported to the committee that 25 out of 26 recommendations in the Bly Report were completed by the end of 2014 (and he will report to the committee regarding the final recommendation which is expected to be completed at the end of 2015).

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SEEAC focus in 2014

* 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. 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 lessons learned across the segment. He twice reported directly to the SEEAC in 2014 and presented detailed reports on his work (including reporting on a number of visits he has made to refineries and other downstream facilities). Mr Wilson will complete his engagement in April 2015 and delivered his final report to the SEEAC in January 2015. The committee wishes to thank him for all of his work during the course of his engagement and believes he has made a lasting and positive impact on the process safety culture in the Downstream segment.

Reports from group audit and group ethics and compliance

The committee received quarterly reports from both of these functions. These included summaries of investigations into significant alleged fraud or misconduct (which are now undertaken through the business integrity team established in 2014). 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 May the chairman and other members of the committee visited Baku in Azerbaijan to examine both offshore facilities (Central Azeri platform) and the onshore gas reception terminal (Sangachal) operated by the group. In October the chairman and another committee member visited operations at the biofuels business in central Brazil. In September all members of the committee visited the Whiting refinery in Indiana, US, as part of a larger board visit. In all cases, the visiting committee members received briefings on operations, the status of local OMS implementation, and risk management and mitigation. Committee members then reported back in detail about each visit to the committee and subsequently to the board. In addition the local management team reported back to the committee regarding the status of the issues raised during the visit.

Committee review

For its 2014 evaluation, the SEEAC examined its performance and effectiveness with a questionnaire administered by external consultants. 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

its work, in particular by giving committee members the ability to examine how risk management is being embedded in businesses and facilities, including management culture.

Gulf of Mexico committee

Chairman s introduction

The Gulf of Mexico committee continues to oversee the group s response to the Deepwater Horizon accident, ensuring that BP fulfils all its legitimate obligations while 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 (MDL) 2179 and 2185, 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 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. Its work is integrated with that of the board, which retains ultimate accountability for oversight of the group s response to the accident.

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Gulf of Mexico committee focus in 2014

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 US.
- Review compliance with government settlement agreements arising out of the Deepwater Horizon accident and oil spill, including the SEC Consent Order, the Department of Justice plea agreement and the EPA administrative agreement, in co-ordination 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
Alan Boeckmann	Member since September 2014

The chairman and the group chief executive attend all meetings of the committee.

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. Active clean-up activities are now complete in all states.

The committee continued to oversee numerous legal matters relating to the Deepwater Horizon accident, including the ruling made in respect of Phase 1 of the trial in MDL 2179 (and the subsequent appeal of that ruling), preparation for the penalty phase of the trial and BP s appeals to the US Court of Appeals for the Fifth Circuit and the US Supreme Court relating to the Court Supervised Settlement Program.

The committee met 11 times in 2014.

Committee review

Each year the Gulf of Mexico committee evaluates its performance and effectiveness. 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 for focus in 2015 included maintaining constructive and challenging engagement with management as well as continuing timely and effective communication of its activities and findings to the board.

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Nomination and chairman s committees

Chairman s introduction

I am pleased to report on the two board committees that 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 the company secretary.

Key responsibilities

- 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.

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 six times during the year.

It continued to reflect on the rhythm of the meetings. As in 2013, the committee held one longer meeting during the year and reviewed board composition and skills in light of BP s strategy.

In 2014 the committee considered the sequencing of board retirements over the coming years and potential board candidates. It is pursuing several promising individuals and appointments are likely to be made in 2015. As part of this, letters of appointment for all non-executive directors were reviewed and amended. The committee considered the chairmanship and membership of each committee. As a result it was agreed that Dame Professor Ann Dowling would take the chair of the remuneration committee when Antony Burgmans steps down from that role in 2015, and that Andrew Shilston and Alan Boeckmann will join the remuneration committee after the 2015 annual general meeting.

The committee considered the feedback from its own evaluation. There were several actions including a greater focus on executive succession and the interaction between the chairman s and nomination committee in this respect. The committee also wishes to make agenda time to consider broader issues such as succession and diversity. Future searches for non-executive directors should generally focus on industry expertise and also consider the split between former chief executive officers and directors with others skills on the board.

Chairman s committee

Role of the committee

To provide a forum for matters to be discussed among the non-executive directors.

Key responsibilities

- Evaluate the performance and the effectiveness of the group chief executive.
- Review the structure and effectiveness of the business organization.
- Review the systems for senior executive development and determine the succession plan for the group chief executive, the executive directors and other senior members of executive management.
- Determine any other matter that 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 during the year

The committee met five times in the year to:

- Assess the effect of sanctions on Russia on BP s relationship with Rosneft.
- Monitor the progress of the Gulf of Mexico litigation.
- Determine the framework for board evaluation in 2015.
- Review the background to the 2015 plan in light of the decline in oil prices.
- Consider the chief executive s plans for the succession and organization of the executive team.
- Evaluate the performance of the chairman and chief executive.

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Directors remuneration report

Chairman s annual statement

Dear shareholder,

2014 started strongly but, as others have commented in this report, ended more turbulently as the price of oil fell, mainly in the last quarter. This formed the backdrop for the decisions of the committee at the end of 2014. The work of the committee is governed by a number of overriding principles. Key among these is seeking a fair outcome in reward that is linked to BP s immediate and long-term performance and strategy delivery. As part of this, the committee seeks to ensure that variable remuneration is based on underlying performance and is not driven by factors over which the directors have no control. All of this work is carried out within the policy framework that was approved overwhelmingly by shareholders earlier in the year.

In this context:

- 2014 saw the end of an improving three-year period for BP. This is demonstrated elsewhere in the report. The high-performance gearing in remuneration of the executive directors reflects good business results through an overall increase in remuneration compared to last year.

- The world is a more uncertain place in 2015. BP has responded broadly to this, including freezing salaries, and the committee has refocused the measures for the annual bonus to reflect new challenges.

- There are clear concerns in society and among shareholders that remuneration for executive directors is simply too much. The policy, now approved by shareholders, is clear and recognizes these concerns particularly by placing limits on the amounts that can be awarded. Equally, this remuneration has to be appropriate to be aligned with the global market for talent in which BP works. Here the committee has to strike a balance.

2014 in retrospect

Our remuneration policy was approved at the 2014 AGM for a three-year period. At the same meeting, a number of shareholders voted against or withheld their votes on our annual remuneration report. There were several reasons for this. There were concerns around our commitment to disclosure of targets, whether prospectively or retrospectively, and the need for additional disclosure when the committee was exercising judgements around qualitative measures. Some shareholders believed that the overall remuneration of the executive directors was excessive.

We are responding to these concerns and are committed to making as full a retrospective disclosure of those targets that we are able to, subject to confidentiality. I believe that this is demonstrated in this year s report, particularly in the tables relating to annual bonus and performance shares. In terms of overall quantum of remuneration, I have previously made clear that the committee understands the concerns felt in society and by some shareholders. The committee, however, believes that these concerns are properly recognized and balanced in the way in which the policy is framed and implemented.

At the time of our last report, the outcome for the performance shares was based on an estimated second place for relative reserves replacement. Once results for the oil majors were publicly available it was assessed that BP was in first place, resulting in a vesting of 45.5% . The awards were adjusted and announced accordingly.

Finally, in July, Iain Conn agreed with the board that he would stand down as a director on 31 December 2014. Iain has made a significant contribution to the company over his long career and, on this basis, the terms of his departure were agreed with the committee within the policy. The terms were promptly communicated on BP s website and are set out again later in this report.

2014 outcomes

BP has performed well in increasingly difficult circumstances. This has been demonstrated by the delivery of the 10-point plan, which the board approved as BP s strategic direction in 2011. In considering performance in 2014 and its effect on remuneration, two areas stand out. Firstly, a key milestone in delivery of the plan was achieving $32.8 billion of operating cash flow«. The excellent performance in this measure had a strong influence on both the annual bonus and the performance share element. The second area with an equally strong influence was safety. Over the three years of the performance share element, performance improved by more than 15% on two of the measures and over 60% on one measure.

Annual bonus

Measures for the annual bonus that focused on safety and value were largely unchanged from previous years to encourage continuity of performance and delivery. There had been a strong safety performance in 2013. We seek continuous improvement in this area and the targets for 2014 were ambitious. Against that background, performance was mixed and showed a modest improvement.

Operating cash stood out as being well ahead of target but underlying replacement cost profit« was below. Seven projects started up in 2014, making 16 major projects« start-ups since the beginning of 2012. All of this resulted in a group performance score of 1.10, compared with a score of 1.32 last year. The committee felt that this score reasonably reflected the overall performance for the year. Following elections by the executive directors, one third of this bonus will be paid in cash and two thirds in shares that are deferred for three years and matched. There is retrospective disclosure of many of the targets for the annual bonus later in this report.

Deferred bonus

2011 deferred bonus share awards became eligible for vesting at the end of 2014. Vesting is dependent on safety and environmental sustainability performance over that period. The committee reviewed this in consultation with the SEEAC. Based on strong and consistent improvement and no significant incidents, the deferred and matching shares vested in full.

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Performance shares

The 2012-2014 performance share plan was, as in the previous year, based on three sets of measures equally weighted; relative total shareholder return (TSR), operating cash flow and finally strategic imperatives, which include relative reserves replacement ratio (RRR), safety and operational risk and rebuilding trust. The committee made its assessment of performance over the three-year period against the agreed targets and its view of the achievements over that time. There were no shares awarded for TSR as the minimum threshold was not reached. As I have mentioned above, there was strong performance against the safety measures and the committee exercised its judgement based on qualitative data in respect of the need to rebuild trust. As for 2013, the assessment was preliminary as the final results from the comparator group for RRR were not available. On the basis of information available, second place was recorded. Based on this preliminary assessment, 60.5% of the shares are expected to vest. The committee believes that this represents a fair outcome for a continually improving performance over the period. Again, there is retrospective disclosure of many of the targets used for the 2012-2014 performance share plan in this report.

2015 and the future

During 2014, BP set out a clear proposition to shareholders aimed at delivering value rather than volume through active portfolio management, growing sustainable free cash flow through capital discipline and growing distributions for shareholders. The company s key performance indicators (KPIs) are designed to measure performance against this proposition. The committee is determined that the remuneration of the directors remains clearly linked to the company s strategy. There has been a refocus of some of the measures for the 2015 annual bonus to reflect this and the current short-term imperatives facing BP. The graphic below sets out BP s strategic priorities and links them to the measures used for short and long term remuneration with further detail in this report.

Policy issues

In 2014, the UK Corporate Governance Code was revised. The Code introduced, on a comply or explain basis, a requirement to introduce malus and clawback provisions into all performance related elements of directors remuneration. The committee has reviewed the terms of the executive directors remuneration and confirmed that malus and clawback provisions exist in all terms save the cash element of the annual bonus. It will propose an appropriate provision on the next occasion that it renews the remuneration policy. The committee also undertook a detailed examination of its tasks. The changes that have been made are set out in more detail later in this report.

Conclusion

Whilst BP has performed well in recent years and momentum has been building, there are clearly more challenging times ahead. We have set out our approach in this changing world. It is likely that, within our policy, we will need to exercise judgement and discretion based on solid data. Should we be required to do so, it will be done within our policy and with subsequent disclosure so that our shareholders are clear on the decisions that we have taken.

Finally, I will be standing down as the chair of the committee in June and I will be succeeded by Professor Dame Ann Dowling. Ann has sat on the committee after joining the board in 2012 and I look forward to introducing her to our shareholders. I would like to thank our shareholders for the support, and the challenge, over the past four years.

Antony Burgmans

Previously, the committee reviewed the executive directors salaries in May each year. In future, it will do so in January for implementation in April, at the same time as the rest of the organization. Given the general company pay freeze, no salary increases were awarded to directors for 2015.

Chairman of the remuneration committee

3 March 2015

« Defined on page 252.

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Remuneration committee report

The committee was made up of the following independent non-executive directors in 2014.

Members
Antony Burgmans (chairman)
George David
Ian Davis
Professor Dame Ann Dowling
In addition, Carl-Henric Svanberg and Bob Dudley normally attend the meetings except for matters relating to their own remuneration.

Key responsibilities

The committee s tasks were reviewed during the year and are as follows:

- Determine the policy for the chairman and the executive directors (the policy) for inclusion in the remuneration policy for all directors as required by the regulations.
- Review and determine as appropriate the terms of engagement, remuneration and termination of employment of the chairman and the executive directors in accordance with the policy, and be responsible for compliance with all remuneration issues relating to the chairman and the executive directors required by the regulations.
- Prepare for the board an annual report to shareholders on the implementation of the policy, so far as it relates to the chairman and the executive directors, as required by the regulations.
- Approve the principles of any equity plan for which shareholder approval is to be sought.

Approve the terms of the remuneration (including pension and termination arrangements) of the executive team as proposed by the group chief executive (GCE).

Approve changes to the design of remuneration as proposed by the GCE, for the group leaders of the company.

Monitor implementation of remuneration for group leaders to ensure alignment and proportionality.

Engage such independent consultants or other advisers as the committee may from time to time deem necessary, at the expense of the company.

In these tasks regulations shall mean regulations made under the Companies Act 2006 from time to time in relation to the remuneration of directors of quoted companies, the UK Corporate Governance Code adopted by the Financial Reporting Council from time to time and the UK Listing Authority s Listing Rules from time to time.

Committee review and composition

The board evaluation process included a separate questionnaire on the work of the remuneration committee. The results were analysed by an external consultant and discussed at the committee s meeting in December 2014. Processes continued to be rated as good to excellent and a number of topics for more in-depth discussion were identified. In particular the committee decided to schedule a longer strategy meeting each year.

George David stands down from the board at the next annual general meeting and will leave the committee. Alan Boeckmann and Andrew Shilston will join the committee after that meeting.

Professor Dame Ann Dowling will take the chair of the committee in June 2015. Antony Burgmans will remain a member of the committee.

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 GCE is consulted on the remuneration of the other executive directors and the executive team and on matters relating to the performance of the

group. Neither he, nor the chairman of the board, participate in decisions on their own remuneration. The group human resources director normally attends, and other executives may attend relevant parts of meetings.

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

During 2014 David Jackson, the company secretary, who is employed by the company and reports to the chairman of the board, acted as secretary to the remuneration committee. The company secretary periodically reviews the independence of the committee s advisers.

Gerrit Aronson, an independent consultant, is the committee s independent adviser. He is engaged directly by the committee. He advises the chairman, the board and the nomination committee on a variety of governance issues. Advice and services on particular remuneration matters were also 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 2014 to the above advisers for the provision of remuneration advice to the committee as set out above (save in respect of legal advice) are as follows:

Gerrit Aronson £140,000

Towers Watson £23,400

Activities during the year

During the year, the committee met five times. Key discussions and decision items are shown in the table below.

Remuneration committee 2014 meetings

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Executive directors

Total remuneration summary 2014

Salary reviewed mid-year and **increased by an average of 3%** for all directors this was in line with average employee increases in the UK and US.

Annual bonus the key focus for 2014 was delivery of the group s 10-point plan, strong operating cash flow, safe and reliable operations and delivery of major projects within the year. Operating cash flow exceeded planned targets. Overall safety results were satisfactory and consolidated the improvements made over the last three years. The underlying operating performance was strong. **Overall group score was 1.10 times target.**

Deferred bonus 2011 deferred bonus was conditional on safety and environmental sustainability performance over the period 2012 through to

2014. There was strong and consistent delivery against this hurdle and **2011 deferred and matched shares vested in full.**

Performance shares vesting was based one third on relative total shareholder return (TSR), one third on operating cash flow and one third on strategic imperatives including safety and operational risk (S&OR), relative reserves replacement ratio (RRR) and rebuilding trust internally and externally. TSR performance did not achieve the minimum level necessary for this part of the award to vest. There was strong operating cash flow. There was similarly strong performance against the strategic imperatives. **On a preliminary assessment 60.5% of the 2012-2014 award are expected to vest.**

Pension pension figures reflect the UK requirements to show 20 times the increase in accrued pension over the year for defined benefit plans, as well as any cash paid in lieu.

Single figure table of remuneration of executive directors in 2014 (audited)

Remuneration is reported in the currency received by the individual

	Bob Dudley thousand		Dr Brian Gilvary thousand		Iain Conn thousand	
Annual remuneration 2014	**2014**	2013	**2014**	2013	**2014**	2013
Salary	**$1,827**	$1,776	**£721**	£700	**£786**	£763
Annual cash bonus[a]	**$1,005**	$2,344	**£396**	£924	**£1,252**	£961
Benefits	**$114**	$90	**£51**	£45	**£55**	£59
Total	**$2,946**	$4,210	**£1,168**	£1,669	**£2,093**	£1,783

Vested equity						
Deferred bonus and match[b]	**$3,401**	$0	**£0**	£0	**£1,698**	£242
Performance shares	**$6,391[c]**	$5,963[d]	**£1,904[c]**	£505	**£2,014[c]**	£1,688[d]
Total	**$9,792**	$5,963	**£1,904**	£505	**£3,712**	£1,930
Total remuneration	**$12,738**	$10,173	**£3,072**	£2,174	**£5,805**	£3,713
Pension						
Pension value increase[e]	**$2,596**	$4,447	**£21**	£44	**£18**	£46
Cash in lieu of future accrual	**N/A**	N/A	**£252**	£245	**£275**	£267
Total including pension	**$15,334**	$14,620	**£3,345**	£2,463	**£6,098**	£4,026

[a] This reflects the amount of bonus paid in cash with the deferred portion as set out in the conditional equity table below. In the case of Iain Conn, there was no deferral of bonus and all bonus was paid in cash.

[b] Value of vested deferred bonus and matching shares. The amounts reported for 2014 relate to the 2011 annual bonus deferred over three years, which vested on 11 February 2015 at the market price of $40.35 and £4.46 and include re-invested dividends on shares vested. The amounts reported for 2013 relate to the 2010 annual bonus.

[c] Represents the assumed vesting of shares in 2015 following the end of the relevant performance period, based on a preliminary assessment of 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 2014 which was £4.27 for ordinary shares and $40.74 for ADSs. The final vesting will be confirmed by the committee in second quarter 2015 and provided in the 2015 Directors remuneration report.

[d] In accordance with UK regulations, in the 2013 single figure table, the performance outcome value was based on an estimated vesting at an assumed share price of £4.69 for ordinary shares and $45.52 for ADSs. In May 2014, after the external data became available, the committee reviewed the relative reserves replacement ratio position and assessed that the group was first place relative to the other oil majors. This resulted in an adjustment to the final vesting from 39.5% to 45.5% . On 15 May 2014, 115,766 ADSs for Bob Dudley and 331,330 shares for Iain Conn vested at prices of $50.90 and £5.03 respectively. The vesting of the final notional dividends prior to the vesting date took place on 24 June 2014 when Bob Dudley received 1,331 ADSs and Iain Conn received 4,122 shares at prices of $52.84 and £5.24 respectively. The 2013 values for the total vesting have increased by $1,440,954 for Bob Dudley and £356,604 for Iain Conn.

[e] Represents the annual increase net of inflation in accrued pension multiplied by 20 as prescribed by UK regulations.

Conditional equity to vest in future years, subject to performance

		Bob Dudley		Dr Brian Gilvary		Iain Conn	
Deferred bonus in respect of bonus year		**2014**	2013	**2014**	2013	**2014**	2013
Total deferred bonus	Value (thousand)	**$2,010**	$1,172	**£793**	£462		£481
Total deferred converted to shares	Shares	**294,108**	149,628	**176,576**	96,653		100,563
Total matched shares	Shares	**294,108**	149,628	**176,576**	96,653		100,563
Vesting date		**Feb 2018**	Feb 2017	**Feb 2018**	Feb 2017		Feb 2017

Release date[a]	**Feb 2021**	Feb 2020	**Feb 2021**	Feb 2020		Feb 2018
Performance share element	**2014-2016**	2013-2015	**2014-2016**	2013-2015	**2014-2016**	2013-2015
Potential maximum shares	**1,304,922**	1,384,026	**605,544**	637,413	**220,043**[b]	463,126[b]
Vesting date	**Feb 2017**	Feb 2016	**Feb 2017**	Feb 2016	**Feb 2017**	Feb 2016
Release date	**Feb 2020**	Feb 2019	**Feb 2020**	Feb 2019	**Feb 2018**	Feb 2017

[a] Deferred shares are released at vesting with the exception of matched shares which normally have a further three-year retention period.
[b] Potential maximum of performance shares element has been pro-rated to reflect actual service during the performance period.

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Total remuneration in more depth

In describing the work and decisions of the committee in 2014, the summary wording of the approved policy has been used to introduce the committee s approach to each element of remuneration. Throughout this report, the word policy refers to the directors remuneration policy

approved by shareholders at the company s annual general meeting on 10 April 2014. BP s strategy is reflected in the measures adopted by the committee for the executive directors and further aligned with those for the senior leadership of the group. The policy is available at *bp.com/remuneration* and is set out in the *BP Annual Report and Form 20-F 2013*.

Salary and benefits

Provides base-level fixed remuneration to reflect the scale and dynamics of the business, and to be competitive with the external market.

Policy summary

Operation and opportunity

Salaries are normally set in the home currency of the executive director and reviewed annually.

Salary levels and total remuneration of oil and other top European multinationals, and related US corporations, are considered by the committee. Internally, increases for the group leaders as well as employees in relevant countries are considered.

Salary increases will be in line with all employee increases in the UK and US and limited to within 2% of average increase for the group leaders.

Benefits reflect home country norms. The current package of benefits will be maintained, although the taxable value may fluctuate.

Performance framework

Salary increases are not directly linked to performance. However a base-line level of personal contribution is needed in order to be considered for a salary increase and exceptional sustained contribution may be grounds for accelerated salary increases.

Base salary

The annual base salaries of the executive directors were reviewed in May 2014. In conducting this review the committee considered all of the factors required by the policy and the overall level of increases for employees in both the UK and the US. They also considered the distribution and average level of increases for group leaders comprising around 500 executives in the group. This averaged 3.1%. Based on this review, salaries were increased by 3% on average, resulting in salaries of $1,854,000 for Bob Dudley, £731,500 for Dr Brian Gilvary and £797,000 for Iain Conn. These increases took effect on 1 July 2014.

2015 implementation

The committee determined that in future years, salaries would be reviewed in January to be effective in April, consistent with the rest of BP s employees. No increases were granted for 2015, in line with the group-wide salary freeze.

Benefits

Executive directors received car-related benefits, security assistance, insurance and medical benefits.

Annual bonus

Provides a variable level of remuneration dependent on short-term performance against the annual plan.

Policy summary

Operation and opportunity

Total overall bonus (before any deferral) is based on performance relative to measures and targets reflected in the annual plan, which in turn reflects BP s strategy.

On-target bonus is 150% of salary with 225% as maximum.

Achieving annual plan objectives equates to on-target bonus. The level of threshold payout for minimum performance varies according to the nature of the measure in question.

Performance framework

Specific measures and targets are determined each year by the remuneration committee.

A proportion will be based on safety and operational risk management and is likely to include measures such as loss of primary containment, recordable injury frequency and tier 1 process safety events.

The principal measures of annual bonus will be based on value creation and may include financial measures such as operating cash flow, replacement cost operating profit and cost management, as well as operating measures such as major project delivery, downstream net income per barrel and upstream unplanned deferrals. The specific metrics chosen each year will be set out and explained in the annual report on remuneration.

Framework

The committee determined performance measures and their weightings for the 2014 annual bonus at the beginning of the performance year, focusing on two key priorities: safety and value.

Performance measures remained largely unchanged from last year in order to maintain continuity and build momentum for delivery of the 10-point plan. Measures and targets reflected the business plan for the year and were set so that meeting plan would result in an on target bonus reward.

Bob Dudley and Dr Brian Gilvary s annual bonus was based 100% on group annual bonus objectives.

Safety made up 30% of group annual bonus objectives. Safety measures related to loss of primary containment, tier 1 process safety events and recordable injury frequency. Challenging targets for these measures were set, both to build on the improving trend of the last three years and to continue to reduce the number of safety events.

Value made up 70% of group annual bonus objectives. Measures included delivering operating cash flow in line with the 10-point plan; increasing underlying replacement cost profit; reducing corporate and functional costs; improving operating efficiency in upstream operations by minimizing unplanned deferrals; completing major projects planned within the year; and delivering downstream profit per barrel of refining capacity.

Iain Conn s annual bonus was based 70% against the group annual bonus objectives and 30% against safety, operating efficiency and profitability performance of the downstream segment.

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2014 outcomes

In January 2015, the committee considered the group s performance during 2014 against the measures and targets set out below.

In safety, the committee recognized that ambitious targets had been set and the improvements in the year varied between the measures. In loss of primary containment, the improvement was above the threshold but below the target resulting in a weighted score of 7.96 out of 10; similarly in recordable injury frequency (RIF) the improvement was above the threshold but below the target resulting in a weighted score of 6.07 out of 10. Importantly, these levels of performance still represented an improvement on the previous year. Tier 1 process safety events did not reach the threshold expectation and therefore did not score. The outcomes relative to these targets were mixed, however the underlying trend remained positive, reflecting continued improvement over the past three years.

Operating cash flow of $32.8 billion was well ahead of target of $30 billion. Underlying replacement cost profit of $12.1 billion was below target of $14.5 billion. Through greater simplification and efficiency across all functions, corporate and functional costs were reduced by 9% against a

targeted reduction of 7%. In terms of operational performance seven major projects were successfully delivered in 2014 against the plan of six. Upstream unplanned deferrals were reduced by 6% against a targeted reduction of 9%. Downstream net income per barrel of $4.4/bbl was below target of $6.4/bbl.

Based on these results, the overall group performance score was 1.10. The committee, as is its normal practice, considered this result in the context of the underlying financial performance of the group, competitors results, shareholder feedback and input from the board and other committees. After review, it concluded that this result fairly represented the overall performance of the business during the year.

In the downstream segment, safety results were good with improvements in loss of primary containment and process safety tier 2 events. Operating cash flow was ahead of plan but refining availability and net income per barrel were below plan expectations. The performance score was 0.98.

A summary of the outcomes for each measure, set against the target for the year, is shown below.

[a] Defined by American Petroleum Institute (API).

[b] Assessment of the financial outcomes was done using the same conditions as the targets were set at oil price, refining margin and other environmental factors were taken into account.

The overall bonus for directors was determined by multiplying the group score of 1.10 times target by the on-target bonus level of 150% of salary. Bob Dudley s total overall bonus was 165% of salary, as was Dr Brian Gilvary s. Iain Conn s total overall bonus was 159% of salary, based on both group and downstream segment performance (accounting for 30% of his bonus). Under the terms of the deferred element of the EDIP, one third of the total bonus is paid in cash. A director is required to defer a further third and the final third is paid either in cash or voluntarily deferred at the individual s election.

Bob Dudley and Dr Brian Gilvary have both elected to defer the final third of their annual bonus. Iain Conn, who left at the end of the year, was not eligible for deferral and so all his bonus (reflecting his 12 months of service) was paid in cash. The following table outlines the amounts paid in cash and amounts deferred into shares.

Annual bonus summary

	Overall bonus	Paid in cash	Deferred in BP shares
Bob Dudley	$3,014,550	$1,004,850	$2,009,700
Dr Brian Gilvary	£1,189,238	£396,413	£792,825
Iain Conn	£1,252,480	£1,252,480	£0

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2015 implementation

For 2015, 100% of Bob Dudley s and Dr Brian Gilvary s bonus will be based on group results.

The 2015 bonus plan has been set in the context of recent group achievements (delivery of the 10-point plan), current short-term imperatives and the group s strategy. The committee will continue to focus on the two overall themes of safety and value. In order to focus on priorities of the short term, the number of value measures has been reduced from six in 2014 to five in 2015. The measures reflect the current short term imperatives and tie back to the 2015 priorities in the group s annual plan. Targets for each measure are challenging but realistic and have been set in the context of the current environment.

Continued improvement in safety remains a group priority and is fully reflected in the measures. Safety will continue to have a 30% weight in the overall bonus plan. The value measures are now more heavily weighted on operating cash flow and underlying replacement cost profit. Capital and cost discipline are reflected through two measures net investment (organic) and corporate and functional cost management. The delivery of major projects remains a point of focus. All of these value measures are key to short-term performance within the group and will have an overall weight of 70% for the annual bonus 2015.

The committee agreed the performance measures for the 2015 annual cash bonus as set out opposite.

Targets will be disclosed retrospectively in the 2015 remuneration report to the extent that they are no longer considered commercially sensitive.

Deferred bonus

Reinforces the long-term nature of the business and the importance of sustainability, linking a further part of remuneration to equity.

Policy summary

Operation and opportunity

A third of the annual bonus is required to be deferred and up to a further third can be deferred voluntarily. This deferred bonus is awarded in shares.

Deferred shares are matched on a one-for-one basis, and both deferred and matched shares vest after three years depending on an assessment by the committee of safety and environmental sustainability over the three-year period.

Where shares vest, additional shares representing the value of reinvested dividends are added.

Before being released, all matched shares that vest after the three-year performance period are subject (after tax) to an additional three-year retention period.

Performance framework

Both deferred and matched shares must pass an additional hurdle related to safety and environmental sustainability performance in order to vest.

If there has been a material deterioration in safety and environmental metrics, or there have been major incidents revealing underlying weaknesses in safety and environmental management then the committee, with advice from the safety, ethics and environmental assurance committee, may conclude that shares vest in part, or not at all.

All deferred shares are subject to clawback provisions if they are found to have been granted on the basis of materially misstated financial or other data.

2014 outcomes

Both Bob Dudley and Iain Conn deferred two thirds of their 2011 annual bonus in accordance with the terms of the policy in place at the time of deferral.

The three-year performance period concluded at the end of 2014. The committee reviewed safety and environmental sustainability performance over this period and sought the input of the safety, ethics and environment assurance committee (SEEAC). Over the three-year period 2012-2014 safety measures showed steady improvement. All performance hurdles were met and the group-wide operating management system« is now sufficiently embedded throughout the organization to continue driving improvement in environmental as well as safety areas.

Following the committee s review, full vesting of the deferred and matched shares for the 2011 deferred bonus was approved, as shown in the following table (as well as in the single figure table on page 75).

2011 deferred bonus vesting

Name	Shares deferred	Vesting agreed	Total shares including dividends	Total value at vesting
Bob Dudley	436,824	100%	505,782	$3,401,384
Iain Conn	322,608	100%	380,785	£1,698,301

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 84.

Details of the deferred bonus awards made to the executive directors in early 2014, in relation to 2013 annual bonuses, were set out in last year s report. A summary of these awards is included on page 84.

2015 implementation

The committee has determined that the safety and environmental sustainability hurdle will continue to apply to shares deferred from the 2014 bonus. All matched shares that vest in 2018 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 in 2021. This further reinforces long-term shareholder alignment and the nature of the group s business. Both Bob Dudley and Dr Brian Gilvary deferred two thirds of their 2014 annual bonus.

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Performance shares

Ties the largest part of remuneration to long-term performance. The level varies according to performance relative to measures linked directly to strategic priorities.

Policy summary

Operation and opportunity

Shares up to a maximum value of five and a half times salary for the group chief executive and four times salary for the other executive directors can be awarded annually.

Vesting of shares after three years is dependent on performance relative to measures and targets reflecting BP s strategy.

Where shares vest, additional shares representing the value of reinvested dividends are added.

Before being released, those shares that vest after the three-year performance period are subject (after tax) to an additional three-year retention period.

Performance framework

Performance shares will vest on the following three performance measures:

- Total shareholder return relative to other oil majors.
- Operating cash flow.
- Strategic imperatives.

Measures based on relative performance to oil majors will vest 100%, 80%, 25% for first, second and third place finish respectively and 0% for fourth or fifth position.

The committee identifies the specific strategic imperatives to be included every year and may also alter the other measures if others are deemed to be more aligned to strategic priorities. These are explained in the annual report on remuneration.

The committee may exercise judgement to adjust vesting outcomes if it concludes that the formulaic approach does not reflect the true underlying performance of the company s business or is inconsistent with shareholder benefits.

All performance shares are subject to clawback provisions if they are found to have been granted on the basis of materially misstated financial or other data.

Framework

Performance shares were conditionally awarded to each executive director in 2012. Maximum awards under the policy were granted representing five-and-a-half-times salary for Bob Dudley and four-times salary for Dr Brian Gilvary and Iain Conn. Vesting of these awards was subject to delivering targets set over the three-year performance period.

One third of the award was based on relative total shareholder return (TSR), one third on operating cash flow and one third on strategic imperatives which were relative reserves replacement ratio (RRR), safety and operational risk (S&OR) and rebuilding trust internally and externally, all equally weighted. Again, performance against each of these measures was designed to be aligned with group strategy, future direction and creation of shareholder value.

Relative TSR represents the change in value of a BP shareholding between the average of the fourth quarter of 2011 and the fourth quarter of 2014 compared to other oil majors (dividends are re-invested). RRR represents organic reserves added over the three-year performance period divided by the reserves extracted. This ratio is ranked against like-for-like organic RRR for other oil major peers.

The 2012-2014 comparator group for relative TSR (33.3% weight) and relative RRR (11.1% weight) was Chevron, ExxonMobil, Shell and Total. The number of conditional shares that would vest for each of the relative performance measures for first, second and third place was set at the start of 2012 and equals 100%, 70% and 35% respectively. This reflects the approved rules applicable to the 2012-2014 plan. No shares would vest for fourth or fifth place.

For S&OR, percentage improvement targets were set. For rebuilding trust measures, the committee determined that it would use qualitative and quantitative data to assess the improvement of external and internal perception of the group and to gauge whether trust was being rebuilt. Judgement would then be exercised as appropriate.

2014 outcomes

The committee considered the performance of the group over the three-year period of the plan and the specific achievements against each of the targets set for the measures. Based on a preliminary assessment of relative RRR, 60.5% of the shares awarded in the 2012-2014 plan are expected to vest.

Relative TSR did not achieve the minimum required for any vesting. The significant weight associated with this measure (one third in total) aligns the actual value delivered to executive directors with that to shareholders.

Operating cash flow, representing a further one third of the award, was $32.8 billion. This notably exceeded the target set in 2011 to increase operating cash flow by more than 50% between 2012 and 2014 at $100/bbl. Consequently, maximum shares for this component will vest.

Strategic imperatives represented the final third. These included relative RRR, S&OR, and rebuilding trust internally and externally. These elements are discussed individually below.

Preliminary assessment of BP s relative RRR indicated a positive outcome with a minimum expected second place amongst the comparator group. The final ranking will be determined once the actual results for 2014 have been published by other comparator companies. For the purposes of this report, and in accordance with the UK regulations, second place has been assumed. Any adjustment to this will be reported in next year s annual report on remuneration. Based on a provisional second place assessment, 7.8% of the maximum of 11.1% shares are expected to vest for RRR.

S&OR has improved significantly over the 2012-2014 period. Loss of primary containment showed a reduction of 32%, the number of reported work related incidents (RIFs) reduced by 15% and tier 1 process safety events reduced by 62%. The underlying trend of continuing improvement over the past three years has been very positive. Consequently, the maximum of 11.1% shares will vest for the safety measures.

In 2011, shortly after the Deepwater Horizon incident, restoring trust both externally and internally was an important priority for the group and, as such, featured as one of the strategic imperatives of the plan. Since then, external and internal trust has been measured by surveys conducted with external audiences and internally with employees. External trust is tracked through six indicators with key stakeholders in the US and UK. Over the three years, external surveys showed improvements ranging from one to six percent with different external audiences.

Employee engagement is assessed by an index which measures employees perceptions of BP including understanding of business priorities, trust in BP leaders and confidence in BP s future strategy. This index has shown a four percent improvement since 2011 and a two percent improvement since 2012 across different levels of the organization.

« Defined on page 252.

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The results of this index were benchmarked against external data and were particularly encouraging.

Recognizing the need to make further progress in this area, the committee determined that 8.3% of the maximum 11.1% of shares will vest for the rebuilding trust measure.

As in past years, the committee also considered the overall performance of the group during the period and whether any other factors should be taken into account. Following this review, the committee assessed that a preliminary 60.5% vesting was a fair reflection of the overall performance pending confirmation of the reserves replacement result. This will result in the vesting shown in the table.

The vested shares for current executive directors are subject to a further three-year retention period before they will be released to the individuals in 2018.

2012-2014 performance shares preliminary outcome

	Shares awarded	Shares vested inc dividends		Value of vested shares
Bob Dudley	1,343,712	941,286	$	6,391,332
Dr Brian Gilvary	624,434	445,912	£	1,904,044
Iain Conn	660,633	471,761	£	2,014,419

The measures, targets and weight for the plan as well as, on a preliminary basis, the outcomes achieved are shown below.

[a] Safety includes loss of primary containment, tier 1 process safety event (defined by API) and recordable injury frequency.

[b] This represents a preliminary assessment.

2011-2013 final outcomes confirmation

Last year it was reported that the committee had made a preliminary assessment of second place for the relative RRR in the 2011-2013 performance shares element. In May 2014 the committee reviewed the results for all comparator companies as published in their reports and accounts and assessed that BP was in first place relative to other oil majors and that the full 20% of shares would vest for this performance measure as opposed to 14% for second place. This resulted in a final vesting of 45.5% from 39.5% for the entire award. This is reflected in the single figure table on page 75.

2015 implementation

Shares were awarded in February 2015 to the maximum value allowed under the policy, five-and-a-half-times salary for Bob Dudley and four-times salary for Dr Brian Gilvary (see table on page 85). These have been awarded under the performance share element of the EDIP and are subject to a three-year performance period. Those shares that vest are subject, after tax, to an additional three-year retention period. The 2015-2017 performance share element will be assessed over three years based on the following measures: relative TSR (one third); cumulative operating cash flow (one third); and strategic imperatives (one third) including relative RRR; S&OR risk assessment; and major project delivery.

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These measures continue to be aligned with BP s strategic priorities of safe, reliable and compliant operations, major project delivery, disciplined financial choices and growing our exploration position.

TSR and RRR will be assessed on a relative basis compared with the other oil majors Chevron, ExxonMobil, Shell and Total with the following vesting schedule.

The committee has agreed targets and ranges for measures that will be used to assess performance at the end of the three-year performance period and will be disclosed retrospectively.

Relative performance ranking BP s ranking place versus oil majors	Vesting percentage for each relative performance measure
First	100%
Second	80%
Third	25%
Fourth or fifth	Nil

Pension

Recognizes competitive practice in home country.

Policy summary

Operation and opportunity

Executive directors participate in the company pension schemes that apply in their home country.
Current UK executive directors remain on a defined benefit pension plan and receive a cash supplement of 35% of salary in lieu of future service accrual when they exceed the annual allowance set by legislation.
Current US executive directors participate in transition arrangements related to heritage plans of Amoco and Arco and normal defined benefit plans that apply to executives with an accrual rate of 1.3% of final earnings (salary plus bonus) for each year of service.

Performance framework

Pension in the UK is not directly linked to performance.
Pension in the US includes bonus in determining benefit level.

Framework

Executive directors are eligible to participate in group pension schemes that apply in their home countries which follow national norms in terms of structure and levels.

US pension

Bob Dudley participates in the US plans. 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 formulas 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 (1) 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 (2) 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 pension

Iain Conn and Dr Brian Gilvary participate in a UK final salary pension scheme in respect of service prior to 1 April 2011. This scheme provides a pension relating to length of pensionable service and final pensionable salary. 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 2014 received cash supplements of 35% of salary in lieu of future service accrual.

In the event of retirement before age 60, the following early retirement terms would apply:

On retirement between 55 and 60, in circumstances approved by the committee, an immediate unreduced pension in respect of the proportion of their benefit for service up to 30 November 2006, and subject to such reduction as the scheme actuary certifies in respect of the period of service after 1 December 2006. The scheme actuary has, to date, applied a reduction of 3% per annum for each year retirement precedes 60 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.

On leaving before age 55, in circumstances approved by the committee, a deferred pension payable from 55 or later, with early retirement terms if it is paid before 60 as set out above.

Irrespective of this, on leaving in circumstances of total incapacity, an immediate unreduced pension is payable from their leaving date.

On leaving BP, Iain Conn is entitled to a deferred pension payable from age 55 or later. The early retirement terms applying to this pension are as set out above.

2014 outcomes

In 2014, Mr Dudley s accrued pension increased, net of inflation, by $130,000; Dr Gilvary s by £1,100 and Mr Conn s by £900. These increases have been reflected in the single figure table on page 75 by multiplying them by twenty in accordance with the requirements of the UK regulations. Dr Gilvary and Mr Conn participate in the UK pension arrangements described above. Both individuals have exceeded the annual or lifetime allowance under UK pensions legislation and, in accordance with the policy, receive a cash supplement of 35% of salary. These cash supplements have been separately identified in the single figure table on page 75.

Mr Dudley participates in the transitional arrangements in the US plans described above. These are aimed at an accrual rate of 1.3% of final earnings (which include salary and bonus), for each year of service.

The committee continues to keep under review the increase in the value of pension benefits for individual directors. There are significant differences in calculation of pensions between the UK and the US. US pension benefits are not subject to cost of living adjustments after retirement as they are in the UK. Equally, transfer values are frequently influenced by changes in interest rates and discount factors.

The committee will continue to make the required disclosures in accordance with the UK regulations; however, given the issues and differences set out above, the committee would note that 12 to 14 would be a typical annuity factor in the US compared with the factor of 20 upon which the UK regulations are based.

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Shareholder engagement

The committee values its dialogue with major shareholders on remuneration matters. During the year, the committee s chairman, the committee s independent adviser and the company secretary held individual meetings with shareholders to ascertain their views and discuss important aspects of the committee s policy and its implementation. They also met key proxy advisers. These meetings supplemented a group meeting of major shareholders with all committee chairs and the chairman which took place in March 2014, as well as an investor relations programme including a regular ongoing dialogue between the chairman and shareholders. Throughout the year this engagement provided the committee with an important and direct perspective of shareholder views and, together with the voting results on remuneration matters at the AGM, was considered when making decisions.

Shareholders who voted against the report or withheld their vote did so for several reasons. These related principally to insufficient detailed information to explain vesting outcomes and no firm commitment to retrospective disclosure of targets currently deemed to be commercially sensitive. For some, quantum was also an issue.

In his engagement, the chairman of the committee has sought to address these issues. While the absolute quantum of remuneration is a product of the implementation of the approved policy and of the performance of the group, additional disclosure is now part of this report. Specifically, the committee now discloses targets retrospectively for both annual bonus and long-term performance shares unless there are specific confidentiality issues.

The board s annual report on remuneration was approved by shareholders at the 2014 AGM. The votes on the report are shown below.

2014 AGM directors remuneration report vote results

Year	% vote for	% vote against	Votes withheld
2014	83.9%	16.1%	2,218,417,773

The committee s remuneration policy was approved by shareholders at the 2014 AGM. The votes on the policy are shown below.

2014 AGM directors remuneration policy vote results

Year	% vote for	% vote against	Votes withheld
2014	96.4%	3.6%	125,217,443

The shareholder approved policy now governs the remuneration of the directors for a period of three years expiring in 2017. It is the board s intention that the policy be renewed at the AGM in 2017.

See *bp.com/remuneration* for a copy of the approved policy.

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 2014 are shown below.

Director	Appointee company	Additional position held at appointee company	Total fees
Bob Dudley	Rosneft[a]	Director	0
Iain Conn	BT Group plc[b]	Non-executive director	£ 54,000
	Rolls-Royce plc[c]	Senior independent director and chairman of the ethics committee	£ 29,300

[a] Bob Dudley holds this appointment as a result of the company s shareholding in Rosneft.
[b] Appointed 1 June 2014.
[c] Resigned 23 May 2014.

Executive director leaving the board

Iain Conn resigned as a director of the company and left BP s employment on 31 December 2014. This decision was announced on 24 July 2014, and he served BP on his existing contractual terms until 31 December 2014 while working five months of the 12 months notice period specified in his service contract. His settlement agreement dated 24 July 2014 is in accordance with the policy and details are set out in the summary below.

Certain aspects of the arrangements described involved the exercise of discretion by the committee in his favour. The committee was satisfied that this was appropriate in view of his long and successful career with BP.

lain Conn was potentially entitled to a termination payment of up to £453,677, calculated as approximately seven months of his base salary of £797,000 per annum. This was to be paid in seven monthly instalments from January 2015, but would cease to be payable in the event that he commenced another employment prior to 24 July 2015. lain Conn commenced employment with Centrica plc on 1 January 2015 and, accordingly, no termination payment was made to him.

lain Conn worked for the full 2014 financial year, and so was eligible for an annual bonus payment paid in cash. The amount of this bonus is stated on page 77.

lain Conn is entitled to an early retirement pension from age 55. In respect of service from 1 December 2006 to his leaving date, he will be subject to a 3% per annum reduction in his pension from age 55.

The share awards held by Iain Conn under the EDIP have been preserved in accordance with the good leaver provisions and will vest at the normal date, to the extent that performance targets are met:

Performance share awards granted in 2012, 2013 and 2014 (all of which will be pro-rated to reflect Iain Conn s period of service within the performance cycle); and

Compulsory deferred bonus awards granted in 2012, 2013 and 2014, voluntary deferred bonus awards granted in 2012 and 2013 and matching share awards granted in 2012, 2013 and 2014. The vesting of the matching share awards (but not the compulsory deferred bonus or the voluntary deferred bonus) will be subject to time pro-rating.

Information on these preserved share awards (including the vesting of share awards in the period up to 23 February 2015 and details of additional shares awarded representing re-invested dividends on such vested awards) is shown (pro-rated as appropriate) on pages 84 and 85.

The information relating to the vesting of share awards will be updated in the 2015 and 2016 remuneration reports.

To the extent that matching share awards granted in 2014 and any performance share awards vest, the post-tax number of shares will be subject to a twelve-month retention period. Vested performance share awards that are currently within their three-year post-vesting retention period must be retained until 31 December 2015.

Iain Conn will continue to be covered by the company s D&O insurance and his indemnity in respect of third-party liabilities will continue in force according to its terms. The company made a contribution towards his legal fees in connection with these arrangements.

Historical data and statistics

Historical TSR performance

This graph shows the growth in value of a hypothetical £100 holding in BP p.l.c. ordinary shares over six years, relative to a hypothetical £100 holding in the FTSE 100 Index of which the company is a constituent. The values of the hypothetical £100 holdings at the end of the six-year period were £107.45 and £194.77 respectively.

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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	$14,620[d]	88	45.5
2014	Dudley	$15,334	73	60.5

[a] Total remuneration figures include pension and are shown as reported each year in the respective Directors remuneration report with the exception of 2012 and 2013 which are restated in line with the figures reported in the single figure tables in this report and in 2013.

[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 Tony Hayward and Bob Dudley, although Bob Dudley did not become CEO until October 2010.

[d] This number is detailed in the single figure table on page 75 and includes the actual outcomes of the 2011-2013 performance share vesting.

Relative importance of spend on pay (million)

[a] Total remuneration reflects overall employee costs. See Financial statements Note 33 for further information.

[b] Capital investment reflects organic capital expenditure«. See footnote a on page 208 for further information.

[c] See Financial statements Note 29 for further information.

[d] Dividends includes both scrip dividends as well as those paid in cash. See Financial statements Note 8 for further information.

Percentage change in CEO remuneration

Comparing 2014 to 2013	Salary	Benefits	Bonus
% change in CEO remuneration	2.9%	26.7%	-14.2%
% change in comparator group remuneration	3.4%[a]	0.0%[b]	-7.7%

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. This is the average across the comparator group.

[b] There was no change in employee benefits structure. Those benefits that are linked to salary have changed in line with base salary increases.

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 23 February 2015 from the directors interests shown below plus the assumed vesting of the 2012-2014 performance shares and is consistent with the figures reported in the single figure table on page 75.

	Appointment date	Value of current shareholding	% of policy achieved
Bob Dudley	October 2010	$10,147,581	109
Dr Brian Gilvary	January 2012	£3,618,299	99

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 have sold shares that vested from the EDIP.

The figures below indicate and include all 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 as at the applicable dates.

Current directors	Ordinary shares or equivalents at 1 Jan 2014	Ordinary shares or equivalents at 31 Dec 2014	Change from 31 Dec 2014 to 23 Feb 2015	Ordinary shares or equivalents total at 23 Feb 2015
Bob Dudley[a]	355,707	738,858	267,582	1,006,440
Dr Brian Gilvary	412,973	545,217	44,928	590,145
Former executive director				
Iain Conn[b]	600,272	826,602		

[a] Held as ADSs.

[b] Includes 48,024 ordinary shares held as ADSs.

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.

Current directors	Performance shares at 1 Jan 2014	Performance shares at 31 Dec 2014	Change from 31 Dec 2014 to 23 Feb 2015	Performance shares total at 23 Feb 2015
Bob Dudley[a]	4,953,654	5,227,500	1,653,162	6,880,662
Dr Brian Gilvary	1,599,607	2,375,957	1,038,398	3,414,355
Former executive director				
Iain Conn	2,666,314	2,069,321		

[a] Held as ADSs.

At 23 February 2015, 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 85.

Current director	Options	Restricted shares
Dr Brian Gilvary	504,191	
Former executive director		
Iain Conn		

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 other members of senior management who own more than 1% of the ordinary shares in issue. At 23 February 2015, all directors and other members of senior management as a group held interests of 12,980,342 ordinary shares or their calculated equivalent, 10,295,017 performance shares or their calculated equivalent and 6,051,908 options over ordinary shares or their calculated equivalent under the BP group share option schemes. Senior management comprises members of the executive team. See pages 56-57 for further information.

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udited)[a]

Bonus year	Type	Performance period	Date of award of deferred shares	Deferred share element interests Potential maximum deferred shares At 1 Jan 2014	Awarded 2014	At 31 Dec 2014	Awarded 2015	Interests vested in 20 Number of ordinary shares vested	Vesting da
2011	Comp	2012-2014	08 Mar 2012	109,206		109,206		126,444[c]	11 Feb 20
	Vol	2012-2014	08 Mar 2012	109,206		109,206		126,444[c]	11 Feb 20
	Mat	2012-2014	08 Mar 2012	218,412		218,412		252,894[c]	11 Feb 20
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[e]	Comp	2014-2016	12 Feb 2014		149,628	149,628			
	Mat	2014-2016	12 Feb 2014		149,628	149,628			
2014[e]	Comp	2015-2017	11 Feb 2015				147,054		
	Vol	2015-2017	11 Feb 2015				147,054		
	Mat	2015-2017	11 Feb 2015				294,108		
2010	DAB[f]	2011-2013	14 Mar 2011	44,971				51,118[c]	9 Jan 20
2011	DAB[f]	2012-2014	15 Mar 2012	73,624		73,624		84,491[c]	15 Jan 20
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[e]	Comp	2014-2016	12 Feb 2014		96,653	96,653			
	Mat	2014-2016	12 Feb 2014		96,653	96,653			
2014[e]	Comp	2015-2017	11 Feb 2015				88,288		
	Vol	2015-2017	11 Feb 2015				88,288		
	Mat	2015-2017	11 Feb 2015				176,576		
directors									
2010	Comp	2011-2013	09 Mar 2011	21,384				24,670[c]	12 Feb 20
	Mat	2011-2013	09 Mar 2011	21,384				24,670[c]	12 Feb 20
2011	Comp	2012-2014	08 Mar 2012	80,652		80,652		95,196[c]	11 Feb 20
	Vol	2012-2014	08 Mar 2012	80,652		80,652		95,196[c]	11 Feb 20
	Mat	2012-2014	08 Mar 2012	161,304		161,304		190,393[c]	11 Feb 20
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		107,531[g]			
2013[e]	Comp	2014-2016	12 Feb 2014		100,563	100,563			
	Mat	2014-2016	12 Feb 2014		100,563	33,521[g]			
2010	Comp	2011-2013	09 Mar 2011	26,604				30,174[c]	12 Feb 20
	Vol	2011-2013	09 Mar 2011	26,604				30,174[c]	12 Feb 20
	Mat	2011-2013	09 Mar 2011	44,340[g]				50,292[c]	12 Feb 20
2011	Comp	2012-2014	08 Mar 2012	91,638		91,638		106,104[c]	11 Feb 20
	Vol	2012-2014	08 Mar 2012	91,638		91,638		106,104[c]	11 Feb 20

	Mat	2012-2014	08 Mar 2012	91,638[g]	91,638[g]	106,104[c]	11 Feb 20
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	32,424[g]	32,424[g]		

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] 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 used to determine the total value at vesting on the vesting dates of 9 January 2014, 12 February 2014, 15 January 2015 and 11 February 2015 were £4.97, £4.87, £3.93 and £4.46 respectively and for ADSs on 12 February 2014 and 11 February 2015 were $48.38 and $40.35 respectively.

[d] The face value has been calculated using the market price of ordinary shares on 11 February 2013 of £4.55.

[e] The market price at closing of ordinary shares on 12 February 2014 was £4.87 and for ADSs was $48.38 and on 11 February 2015 was £4.46 and for ADSs was $40.35. The sterling value has been used to calculate the face value.

[f] 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.

[g] All matching shares have been pro-rated to reflect actual service during the performance period and these figures have been used to calculate the face value.

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Performance shares (audited)

		Share element interests				Interests vested in 2014 and 20		
		Potential maximum performance shares[a]				Number of ordinary		
Performance period	Date of award of performance shares	At 1 Jan 2014	Awarded 2014	At 31 Dec 2014	Awarded 2015	shares vested	Vesting date	Fa of t
2011-2013	09 Mar 2011	1,330,332				702,582[c]	15 May 2014[d]	
2012-2014	08 Mar 2012	1,343,712		1,343,712		941,286[c]	March 2015	
2013-2015[e]	11 Feb 2013	1,384,026		1,384,026				6
2014-2016[e]	12 Feb 2014		1,304,922	1,304,922				6
2015-2017[e]	11 Feb 2015				1,501,770			6
2011-2013[f]	14 Mar 2011	67,500				76,726[c]	9 Jan 2014	
2011-2013[g]	14 Mar 2011	22,500				25,824[c]	6 Feb 2014	
2012-2014	08 Mar 2012	624,434		624,434		445,912[c]	March 2015	
2013-2015[e]	11 Feb 2013	637,413		637,413				2
2014-2016[e]	12 Feb 2014		605,544	605,544				2
2015-2017[e]	11 Feb 2015				685,246			3
ecutive directors								
2011-2013	09 Mar 2011	623,025				335,452[c]	15 May 2014[d]	
2012-2014	08 Mar 2012	660,633		660,633		471,761[c]	March 2015	
2013-2015[e]	11 Feb 2013	694,688		463,126[h]				2
2014-2016[e]	12 Feb 2014		660,128	220,043[h]				1
2011-2013	09 Mar 2011	654,498				345,654[c]	15 May 2014[d]	
2012-2014	08 Mar 2012	414,468		414,468[h]		290,346c	March 2015	
2013-2015[e]	11 Feb 2013	142,278		142,278[h]				

[a] 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 9 January 2014 was £4.97, at 6 February 2014 was £4.77 and 15 May 2014 was £5.03 and for ADSs was $50.90. For the assumed vestings dated March 2015 a price of £4.27 per ordinary share and $40.74 per ADS has been used. These are the average prices from the fourth quarter of 2014.

[d] The 2011-2013 award vested on 15 May 2014 with an additional vesting of accrued notional dividends on 24 June 2014 on which the market price of each share was £5.24 and for ADSs was $52.84. For Byron Grote this resulted in an increase in value at vesting of $708,913 and for Bob Dudley and Iain Conn details can be found in the single figure table on page 75.

[e] The market price at closing of ordinary shares on 11 February 2013 was £4.55 and for ADSs was $43.01, on 12 February 2014 was £4.87 and for ADSs was $48.38, and on 11 February 2015 was £4.46 and for ADSs was $40.35.

[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 has been pro-rated to reflect actual service during the performance period and these figures have been used to calculate the face value.

Share interests in share option plans (audited)

tion type	At 1 Jan 2014	Granted	Exercised	At 31 Dec 2014	Option price	Market price at date of exercise	Date from which first exercisable
BP 2011	500,000			500,000	£3.72		07 Sep 2014
SAYE	4,191			4,191	£3.68		01 Sep 2016
e directors							
SAYE	797			[a]	£3.16		
SAYE	3,017			2,005[b]	£3.68		01 Jan 2015

The closing market prices of an ordinary share and of an ADS on 31 December 2014 were £4.11 and $38.12 respectively.

During 2014 the highest market prices were £5.27 and $53.48 respectively and the lowest market prices were £3.64 and $34.88 respectively.

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] The option lapsed on Iain Conn s departure from the board in accordance with the rules.

[b] Potential maximum shares have been pro-rated with a shorter exercise period in accordance with the rules.

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Non-executive directors

This section of the directors remuneration report completes the directors annual report on remuneration with details for the chairman and non-executive directors (NEDs). The board s remuneration policy for the NEDs was approved at the 2014 AGM. This policy was implemented during 2014. There has been no variance of the fees or allowances for the chairman and the NEDs during 2014.

Chairman

Basic fee

Remuneration is in the form of cash fees, payable monthly. Remuneration practice is consistent with recognized best practice standards for a chairman s remuneration and as a UK-listed company, the quantum and structure of the chairman s remuneration will primarily be compared against best UK practice.

Operation and opportunity

The quantum and structure of chairman s remuneration is reviewed annually by the remuneration committee, which makes a recommendation to the board.

Benefits and expenses

The chairman is provided with support and reasonable travelling expenses.

Operation and opportunity

The chairman is provided with an office and full time secretarial and administrative support in London and a contribution to an office and secretarial support in Sweden. A chauffeured car is provided in London, together with security assistance. All reasonable travelling and other expenses (including any relevant tax) incurred in carrying out his duties is reimbursed.

The maximum remuneration for non-executive directors is set in accordance with the Articles of Association.

Fee structure

The table below shows the fee structure for the chairman in place since 1 May 2013. He is not eligible 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.

	Fee level £ thousand
Chairman	785

The table below shows the fees paid for the chairman for the year ending 31 December 2014.

2014 remuneration (audited)

£ thousand		Fees		Benefits[a]		Total
	2014	2013	2014	2013	2014	2013
Carl-Henric Svanberg	785	773	37	49	822	822

[a] Benefits include travel and other expenses relating to the attendance at board and other meetings. Amounts disclosed have been grossed up using a tax rate of 45%, where relevant, as an estimation of tax due.

Chairman s interests

The figures below include all the beneficial and non-beneficial interests of the chairman in shares of BP (or calculated equivalents) that have been disclosed under the DTRs as at the applicable dates. The chairman s holdings represented as a percentage against policy achieved are 610%.

Chairman	Ordinary shares or equivalents at 1 Jan 2014	Ordinary shares or equivalents at 31 Dec 2014	Change from 31 Dec 2014 to 23 Feb 2015	Ordinary shares or equivalents total at 23 Feb 2015
Carl-Henric Svanberg	1,039,276	1,076,695		1,076,695

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Non-executive directors

Basic fee

Remuneration is in the form of cash fees, payable monthly. Remuneration practice is consistent with recognized best practice standards for non- executive directors remuneration and as a UK-listed company, the quantum and structure of NED director remuneration will primarily be compared against best UK practice.

Operation

The quantum and structure of NEDs remuneration is reviewed by the chairman, the group chief executive and the company secretary who make a recommendation to the board; the NEDs do not vote on their own remuneration.

Remuneration for non-executive directors is reviewed annually.

Committee fees and allowances

Intercontinental allowance

The NEDs receive an allowance to reflect the global nature of the Company s business. The allowance is payable for transatlantic or equivalent intercontinental travel for the purpose of attending a board or committee meeting or site visits.

Operation

The allowance will be paid in cash following each event of intercontinental travel.

Committee chairmanship fee

Those NEDs who chair a committee receive an additional fee. The committee chairmanship fee reflects the additional time and responsibility in chairing a committee of the board, including the time spent in preparation and liaising with management.

Committee membership fee

NEDs receive a fee for each committee on which they sit other than as a chairman. The committee membership fee reflects the time spent in attending and preparation for a committee of the board.

Operation

Fees for committee chairmanship and membership are determined annually and paid in cash.

The senior independent director (SID)

In the light of the SID s broader role and responsibilities, the SID is paid a single fee and is entitled to other fees relating to committees whether as chair or member.

Operation

The fee for the SID will be determined from time to time, and is paid in cash monthly.

Benefits and expenses

The NEDs are provided with support and reasonable travelling expenses.

Operation

NEDs are reimbursed for all reasonable travelling and subsistence expenses (including any relevant tax) incurred in carrying out their duties.

Professional fees

Fees will be reimbursed in the form of cash, payable following assistance.

Operation

The reimbursement of professional fees incurred by non-executive directors based outside the UK in connection with advice and assistance on UK tax compliance matters.

The maximum remuneration for non-executive directors is set in accordance with the Articles of Association.

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Fee structure

The table below shows the fee structure for non-executive directors from 1 May 2014:

	Fee level £ thousand
Senior independent director[a]	120
Board member	90
Audit, Gulf of Mexico, remuneration and SEEA committees chairmanship fees[b]	30
Committee membership fee[c]	20
Intercontinental travel allowance	5

[a] The senior independent director is eligible for committee chairmanship fees and intercontinental travel allowance plus any committee membership fees.
[b] For members of the audit, Gulf of Mexico, SEEA and remuneration committees.
[c] Committee chairmen do not receive an additional membership fee for the committee they chair.

2014 remuneration (audited)

£ thousand	Fees		Benefits[a]	Total	
	2014	2013	2014	2014	2013
Paul Anderson	175	175	48	223	175
Alan Boeckmann[b]	70		17	87	
Admiral Frank Bowman	165	165	17	182	165
Antony Burgmans	150	145	9	159	145
Cynthia Carroll	125	120	66	191	120
George David[c]	185	185	18	203	185
Ian Davis	150	150	5	155	150
Professor Dame Ann Dowling[d]	140	140	11	151	140
Brendan Nelson	125	130	16	141	130
Phuthuma Nhleko	150	150	9	159	150
Andrew Shilston	150	150	8	158	150

[a] Benefits include travel and other expenses relating to the attendance at board and other meetings. Amounts disclosed are estimated and have been grossed up using a tax rate of 45%, where relevant, as an estimation of tax due. These are disclosed for 2014 following approval of the policy.
[b] Appointed on 24 July 2014.
[c] In addition, George David received £12,500 for chairing the BP technology advisory council until 1 July 2013.
[d] In addition, Professor Dame Ann 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 2014	Ordinary shares or equivalents at 31 Dec 2014	Change from 31 Dec 2014 to 23 Feb 2015	Ordinary shares or equivalents total at 23 Feb 2015	Value of current shareholding	% of policy achieved
Paul Anderson	30,000[a]	30,000[a]		30,000[a]	$206,100	139
Alan Boeckmann[b]		43,890[a]		43,890[a]	$301,524	203
Admiral Frank Bowman	16,320[a]	16,320[a]		16,320[a]	$112,118	76
Antony Burgmans	10,156	10,156		10,156	£45,194	50
Cynthia Carroll	10,500[a]	10,500[a]		10,500[a]	$72,135	49
George David	579,000[a]	579,000[a]		579,000[a]	$3,977,730	2,684
Ian Davis	11,449	22,420		22,420	£99,769	111
Professor Dame Ann Dowling	22,320	22,320		22,320	£99,324	110
Brendan Nelson	11,040	11,040		11,040	£49,128	55
Phuthuma Nhleko						0
Andrew Shilston	15,000	15,000		15,000	£66,750	56

[a] Held as ADSs.
[b] Appointed on 24 July 2014.

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 2014, he received £100,000 for this role.

This directors remuneration report was approved by the board and signed on its behalf by David J Jackson, company secretary on 3 March 2015.

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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 2014, 31 December 2013 and 1 January 2013, 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 2014. 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 2014, 31 December 2013 and 1 January 2013, and the group results of its operations and its cash flows for each of the three years in the period ended 31 December 2014, 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 on the group financial statements we have considered the adequacy of the disclosure in Note 2 to the financial statements concerning the provisions, future expenditures which cannot be reliably estimated and other contingent liabilities related to the claims, penalties and litigation arising from the Gulf of Mexico oil spill. The total amount that will ultimately be paid by BP in relation to all obligations arising from this significant event is subject to significant uncertainty and the ultimate exposure and cost to BP is dependent on many factors, including but not limited to, the outcomes of numerous, material legal proceedings. Significant uncertainty exists in relation to the amount of claims that will become payable by BP and the amount of fines that will be levied on BP (including any ultimate determination of BP s culpability based on negligence, gross negligence or wilful misconduct). The outcome of litigation and the cost of the longer term environmental consequences of the oil spill are also subject to significant uncertainty. For these reasons it is not possible to estimate reliably the ultimate cost to BP. Our opinion is not qualified in respect of these matters.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), BP p.l.c. s internal control over financial reporting as of 31 December 2014, 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 3 March 2015 expressed an unqualified opinion.

/s/ Ernst & Young LLP

London, United Kingdom

3 March 2015

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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 2014, 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 240. 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 2014, 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 2014 and 2013, 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 2014, and our report dated 3 March 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

London, United Kingdom

3 March 2015

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 3 March 2015, 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

2014 in the following Registration Statements:

Registration Statement on Form F-3 (File Nos. 333-201894 and 333-201894-01) of BP Capital Markets p.l.c. and BP p.l.c.; and

Registration Statements on Form S-8 (File Nos.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, 333-186462, 333-199015, 333-200794, 333-200795 and 333-200796) of BP p.l.c.

/s/ Ernst & Young LLP

London, United Kingdom

3 March 2015

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Group income statement

For the year ended 31 December $ million

	Note	2014	2013	2012
Sales and other operating revenues	4	**353,568**	379,136	375,765
Earnings from joint ventures after interest and tax	14	**570**	447	260
Earnings from associates after interest and tax	15	**2,802**	2,742	3,675
Interest and other income	5	**843**	777	1,677
Gains on sale of businesses and fixed assets	3	**895**	13,115	6,697
Total revenues and other income		**358,678**	396,217	388,074
Purchases	17	**281,907**	298,351	292,774
Production and manufacturing expenses[a]		**27,375**	27,527	33,926
Production and similar taxes	4	**2,958**	7,047	8,158
Depreciation, depletion and amortization	4	**15,163**	13,510	12,687
Impairment and losses on sale of businesses and fixed assets	3	**8,965**	1,961	6,275
Exploration expense	6	**3,632**	3,441	1,475
Distribution and administration expenses		**12,696**	13,070	13,357
Fair value gain on embedded derivatives	28	**(430)**	(459)	(347)
Profit before interest and taxation		**6,412**	31,769	19,769
Finance costs[a]	5	**1,148**	1,068	1,072
Net finance expense relating to pensions and other post-retirement benefits	22	**314**	480	566
Profit before taxation		**4,950**	30,221	18,131
Taxation[a]	7	**947**	6,463	6,880
Profit for the year		**4,003**	23,758	11,251
Attributable to				
BP shareholders	30	**3,780**	23,451	11,017
Non-controlling interests	30	**223**	307	234
		4,003	23,758	11,251
Earnings per share cents				
Profit for the year attributable to BP shareholders				
Basic	9	**20.55**	123.87	57.89
Diluted	9	**20.42**	123.12	57.50

[a] See Note 2 for information on the impact of the Gulf of Mexico oil spill on these income statement line items.

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Group statement of comprehensive income[a]

For the year ended 31 December				$ million
	Note	**2014**	2013	2012
Profit for the year		**4,003**	23,758	11,251
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**(6,838)**	(1,608)	485
Exchange gains (losses) on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**51**	22	(15)
Available-for-sale investments marked to market		**(1)**	(172)	306
Available-for-sale investments reclassified to the income statement		**1**	(523)	(1)
Cash flow hedges marked to market	28	**(155)**	(2,000)	1,466
Cash flow hedges reclassified to the income statement	28	**(73)**	4	62
Cash flow hedges reclassified to the balance sheet	28	**(11)**	17	19
Share of items relating to equity-accounted entities, net of tax		**(2,584)**	(24)	(39)
Income tax relating to items that may be reclassified	7	**147**	147	(170)
		(9,463)	(4,137)	2,113
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	22	**(4,590)**	4,764	(1,572)
Share of items relating to equity-accounted entities, net of tax		**4**	2	(6)
Income tax relating to items that will not be reclassified	7	**1,334**	(1,521)	440
		(3,252)	3,245	(1,138)
Other comprehensive income		**(12,715)**	(892)	975
Total comprehensive income		**(8,712)**	22,866	12,226
Attributable to				
BP shareholders		**(8,903)**	22,574	11,988
Non-controlling interests		**191**	292	238
		(8,712)	22,866	12,226

[a] See Note 30 for further information.

Group statement of changes in equity[a]

								$ million
	Share capital and capital reserves	**Treasury shares**	**Foreign currency translation reserve**	**Fair value reserves**	**Profit and loss account**	**BP shareholders equity**	**Non-controlling interests**	**Total equity**
At 1 January 2014	**43,656**	**(20,971)**	**3,525**	**(695)**	**103,787**	**129,302**	**1,105**	**130,407**
Profit for the year					**3,780**	**3,780**	**223**	**4,003**

Other comprehensive income			**(6,934)**	**(202)**	**(5,547)**	**(12,683)**	**(32)**	**(12,715)**
Total comprehensive income			**(6,934)**	**(202)**	**(1,767)**	**(8,903)**	**191**	**(8,712)**
Dividends					**(5,850)**	**(5,850)**	**(255)**	**(6,105)**
Repurchases of ordinary share capital					**(3,366)**	**(3,366)**		**(3,366)**
Share-based payments, net of tax	**246**	**252**			**(313)**	**185**		**185**
Share of equity-accounted entities changes in equity, net of tax					**73**	**73**		**73**
Transactions involving non-controlling interests							**160**	**160**
At 31 December 2014	**43,902**	**(20,719)**	**(3,409)**	**(897)**	**92,564**	**111,441**	**1,201**	**112,642**
At 1 January 2013	43,513	(21,054)	5,128	1,775	89,184	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			247	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)	103,787	129,302	1,105	130,407
At 1 January 2012	43,454	(21,323)	4,509	267	84,661	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			(44)	284		284
Transactions involving non-controlling interests							33	33
At 31 December 2012	43,513	(21,054)	5,128	1,775	89,184	118,546	1,206	119,752

[a] See Note 30 for further information.

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Group balance sheet

At 31 December			$ million
	Note	**2014**	2013
Non-current assets			
Property, plant and equipment	10	**130,692**	133,690
Goodwill	12	**11,868**	12,181
Intangible assets	13	**20,907**	22,039
Investments in joint ventures	14	**8,753**	9,199
Investments in associates	15	**10,403**	16,636
Other investments	16	**1,228**	1,565
Fixed assets		**183,851**	195,310
Loans		**659**	763
Trade and other receivables	18	**4,787**	5,985
Derivative financial instruments	28	**4,442**	3,509
Prepayments		**964**	922
Deferred tax assets	7	**2,309**	985
Defined benefit pension plan surpluses	22	**31**	1,376
		197,043	208,850
Current assets			
Loans		**333**	216
Inventories	17	**18,373**	29,231
Trade and other receivables	18	**31,038**	39,831
Derivative financial instruments	28	**5,165**	2,675
Prepayments		**1,424**	1,388
Current tax receivable		**837**	512
Other investments	16	**329**	467
Cash and cash equivalents	23	**29,763**	22,520
		87,262	96,840
Total assets		**284,305**	305,690
Current liabilities			
Trade and other payables	20	**40,118**	47,159
Derivative financial instruments	28	**3,689**	2,322
Accruals		**7,102**	8,960
Finance debt	24	**6,877**	7,381
Current tax payable		**2,011**	1,945
Provisions	21	**3,818**	5,045
		63,615	72,812
Non-current liabilities			
Other payables	20	**3,587**	4,756
Derivative financial instruments	28	**3,199**	2,225
Accruals		**861**	547
Finance debt	24	**45,977**	40,811
Deferred tax liabilities	7	**13,893**	17,439
Provisions	21	**29,080**	26,915
Defined benefit pension plan and other post-retirement benefit plan deficits	22	**11,451**	9,778

		108,048	102,471
Total liabilities		**171,663**	175,283
Net assets		**112,642**	130,407
Equity			
BP shareholders equity	30	**111,441**	129,302
Non-controlling interests	30	**1,201**	1,105
Total equity	30	**112,642**	130,407

C-H Svanberg Chairman

R W Dudley Group Chief Executive

3 March 2015

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Group cash flow statement

For the year ended 31 December				$ million
	Note	**2014**	2013	2012
Operating activities				
Profit before taxation		**4,950**	30,221	18,131
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	6	**3,029**	2,710	745
Depreciation, depletion and amortization	4	**15,163**	13,510	12,687
Impairment and (gain) loss on sale of businesses and fixed assets	3	**8,070**	(11,154)	(422)
Earnings from joint ventures and associates		**(3,372)**	(3,189)	(3,935)
Dividends received from joint ventures and associates		**1,911**	1,391	1,763
Interest receivable		**(276)**	(314)	(379)
Interest received		**81**	173	175
Finance costs	5	**1,148**	1,068	1,072
Interest paid		**(937)**	(1,084)	(1,166)
Net finance expense relating to pensions and other post-retirement benefits	22	**314**	480	566
Share-based payments		**379**	297	156
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	22	**(963)**	(920)	(858)
Net charge for provisions, less payments		**1,119**	1,061	5,338
(Increase) decrease in inventories		**10,169**	(1,193)	(1,720)
(Increase) decrease in other current and non-current assets		**3,566**	(2,718)	2,933
Increase (decrease) in other current and non-current liabilities		**(6,810)**	(2,932)	(8,125)
Income taxes paid		**(4,787)**	(6,307)	(6,482)
Net cash provided by operating activities		**32,754**	21,100	20,479
Investing activities				
Capital expenditure		**(22,546)**	(24,520)	(23,222)
Acquisitions, net of cash acquired		**(131)**	(67)	(116)
Investment in joint ventures		**(179)**	(451)	(1,526)
Investment in associates		**(336)**	(4,994)	(54)
Proceeds from disposals of fixed assets	3	**1,820**	18,115	9,992
Proceeds from disposals of businesses, net of cash disposed	3	**1,671**	3,884	1,606
Proceeds from loan repayments		**127**	178	245
Net cash used in investing activities		**(19,574)**	(7,855)	(13,075)
Financing activities				
Net issue (repurchase) of shares		**(4,589)**	(5,358)	122
Proceeds from long-term financing		**12,394**	8,814	11,087
Repayments of long-term financing		**(6,282)**	(5,959)	(7,177)
Net increase (decrease) in short-term debt		**(693)**	(2,019)	(666)
Net increase (decrease) in non-controlling interests		**9**	32	
Dividends paid				
BP shareholders	8	**(5,850)**	(5,441)	(5,294)

Non-controlling interests	**(255)**	(469)	(82)
Net cash used in financing activities	**(5,266)**	(10,400)	(2,010)
Currency translation differences relating to cash and cash equivalents	**(671)**	40	64
Increase in cash and cash equivalents	**7,243**	2,885	5,458
Cash and cash equivalents at beginning of year	**22,520**	19,635	14,177
Cash and cash equivalents at end of year	**29,763**	22,520	19,635

Notes on financial statements

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 2014 were approved and signed by the group chief executive and chairman on 3 March 2015 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 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 2014. The accounting policies that follow have been consistently applied to all years presented.

The consolidated financial statements are presented in US dollars and all values are rounded to the nearest million dollars ($ million), except where otherwise indicated.

Significant 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 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: accounting for 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. 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. Intra-group balances and transactions, including unrealized profits arising from intra-group 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 BP shareholders.

Interests in other entities

Business combinations and goodwill

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. 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 arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount under UK generally accepted accounting practice, less subsequent impairments.

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.

Interests in joint arrangements

The results, assets and liabilities of joint ventures 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. 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

The results, assets and liabilities of associates are incorporated in these financial statements using the equity method of accounting as described below.

Significant estimate or judgement: accounting for interests in other entities

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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

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.

Since 21 March 2013, BP has 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 2014. 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 and he is a member of the Rosneft board s Strategic Planning Committee. 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.

The equity method of accounting

Under the equity method, the investment is carried on the balance sheet at cost plus post-acquisition changes in the group s share of net assets of the 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 of disposal and value in use. If 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 from the date on 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.

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 inventories sold in the period and is arrived at by excluding inventory holding gains and losses from profit. Replacement cost profit for the group is not a recognized measure under IFRS. For further information see Note 4.

Foreign currency translation

In individual subsidiaries, joint ventures and associates, transactions in foreign currencies are initially recorded in the functional currency of those entities 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, unless hedge accounting is applied. 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. In the consolidated financial statements, 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 intra-group 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 related cumulative exchange gains and losses recognized in equity are 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 or amortized once classified as held for sale.

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 trade marks and are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses.

Intangible assets acquired separately from a business are carried initially at cost. The initial cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. An intangible asset acquired as part of a business combination is measured at fair value at the date of acquisition and is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights.

Intangible assets with a finite life are amortized on a straight-line basis over their expected useful lives. For patents, licences and trade marks, 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.

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: oil and natural gas accounting

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. an 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 or 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.

One of the facts and circumstances which indicate that an entity should test such assets for impairment is that the period for which the entity has a right to explore in the specific area has expired or will expire in the near future, and is not expected to be renewed.

BP has leases in the Gulf of Mexico making up a prospect, some with terms which were scheduled to expire at the end of 2013 and some with terms which were scheduled to expire at the end of 2014. A significant proportion of our capitalized exploration and appraisal costs in the Gulf of Mexico relate to this prospect. This prospect requires the development of subsea technology to ensure that the hydrocarbons can be extracted safely. BP is in negotiation with the US Bureau of Safety and Environmental Enforcement in relation to seeking extension of these leases so that the discovered hydrocarbons can be developed. BP remains committed to developing this prospect and expects that the leases will be renewed and, therefore, continues to carry the capitalized costs on its balance sheet.

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, finance 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.

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

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1. Significant accounting policies, judgements, estimates and assumptions continued

item will flow to the group, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. Inspection costs associated with major maintenance programmes are capitalized and amortized over the period to the next inspection. Overhaul costs for major maintenance programmes, and all other maintenance costs are expensed as incurred.

Oil and natural gas properties, including related pipelines, are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, common facilities and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the 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.

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: estimation of oil and natural gas reserves

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 167, which is unaudited. Details on BP s proved reserves and production compliance and governance processes are provided on page 219.

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 2014 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 167. 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 4 respectively.

Impairment of property, plant and equipment, intangible assets, and goodwill

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 or decommissioning costs. 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 of disposal 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.

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 market assumptions, such as oil prices, natural gas prices, refining margins, refined product margins and cost inflation rates, are set by senior management. These market assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability. 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 of disposal is 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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the recoverable amount of the group of cash-generating units to which the goodwill relates should be assessed. In assessing whether goodwill has been impaired, the carrying amount of the group of CGUs (including goodwill) is compared with their recoverable amount. The recoverable amount of a group of CGUs to which goodwill is allocated is the higher of value in use and fair value less costs of disposal. Where the recoverable amount of the group of CGUs to which goodwill has been allocated is less than the carrying amount, an impairment loss is recognized. An impairment loss recognized for goodwill is not reversed in a subsequent period.

Significant estimate or judgement: recoverability of asset carrying values

Determination as to whether, and by how much, an asset or group of CGUs containing goodwill 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.

The estimated future level of production in all impairment tests is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes and other factors.

Fair value less costs of disposal may be determined based on similar recent market transaction data or, where recent market transactions for the asset are not available for reference, using discounted cash flow techniques. Where discounted cash flow analyses are used to calculate fair value less costs of disposal, accounting judgements are made about the assumptions market participants would use when pricing an asset, a CGU or a group of CGUs containing goodwill and the test is performed on a post-tax basis. The discount rate used is the group s post-tax weighted average cost of capital (2014 8%), with a 2% premium added in higher-risk countries. Reserves assumptions for fair value less costs of disposal discounted cash flow tests consider all reserves that a market participant would consider when valuing the asset, which are usually broader in scope than the reserves used in a value-in-use test. Discounted cash flow analyses used to calculate fair value less costs of disposal use market prices for the first five years and long-term price assumptions that are consistent with the assumptions used by the group for investment appraisal purposes thereafter. The long-term oil price assumption used in such tests is $97 per barrel in 2020 and is inflated at a rate of 2.5% per annum for the remaining life of the asset. This long-term assumption is derived from the $80 per barrel real oil price assumption used for investment appraisal. In the current price environment, the market prices used for the first five years of both value-in-use and fair value less costs of disposal impairment tests are particularly volatile. Market prices used for the first five years of both value-in-use and fair value less costs of disposal impairment tests are shown in the table below:

					2014
	2015	**2016**	**2017**	**2018**	**2019**
Brent oil price ($/bbl)	**61**	**69**	**73**	**76**	**77**

Henry Hub natural gas price ($/mmBtu)	**3.11**	**3.53**	**3.82**	**4.00**	**4.15**

					2013
	2014	2015	2016	2017	2018
Brent oil price ($/bbl)	108	102	97	93	90
Henry Hub natural gas price ($/mmBtu)	3.86	4.02	4.10	4.17	4.27

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. In 2014 the discount rate used for value-in-use calculations was 12% nominal (2013 12% nominal), with a 2% premium added in higher-risk countries. The discount rates applied in assessments of impairment are reassessed each year. Reserves assumptions for value-in-use tests are confined to proved and sanctioned probable reserves. For value-in-use calculations, prices for oil and natural gas used for future cash flow calculations are based on market prices for the first five years (consistent with those shown in the table above) and the group s flat nominal long-term price assumptions thereafter. As at 31 December 2014, the group s long-term flat nominal price assumptions were $90 per barrel for Brent and $6.50/mmBtu for Henry Hub (2013 $90 per barrel and $6.50/mmBtu). These long-term price assumptions are subject to periodic review and revision.

Irrespective of whether there is any indication of impairment, BP is required to test annually for impairment of goodwill acquired in a business combination. The group carries goodwill of approximately $11.9 billion on its balance sheet (2013 $12.2 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. In testing goodwill for impairment, the group uses the approach described above to determine recoverable amount. 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 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 3 and details on the carrying amounts of assets are shown in Note 10, Note 12 and Note 13.

Inventories

Inventories, other than inventories 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, adjusted where the sale of inventories after the reporting period gives evidence about their net realizable value at the end of the period.

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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

Leases

Finance leases 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.

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 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

These 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 measured at amortized cost using the effective interest method, less any impairment.

Available-for-sale 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, and, for available-for-sale debt instruments, 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 loans and receivables

The group assesses at each balance sheet date whether a financial asset or group of financial assets is impaired. 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: recoverability of trade receivables

Judgements are required in assessing the recoverability of overdue trade receivables and determining whether a provision against the future recoverability of those receivables is required. Factors considered include the credit rating of the counterparty, the amount and timing of anticipated future payments and any possible actions that can be taken to mitigate the risk of non-payment. See Note 27 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

These 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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

Derivative financial instruments and hedging activities

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices as well as for trading purposes. These derivative financial instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments as if the contracts were financial instruments, with the exception of contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the group s expected purchase, sale or usage requirements, are accounted for as financial instruments. Gains or losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

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 attributable to either 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. The group applies fair value hedge accounting when hedging interest rate risk on fixed rate borrowings.

If the criteria for hedge accounting are no longer met, or if the group revokes the designation, the accumulated adjustment to the carrying amount of a hedged item at such time is then amortized to profit or loss over the remaining period to maturity.

Cash flow hedges

The effective portion of the gain or loss on a cash flow 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 reclassified to the income statement when the hedged transaction affects profit or loss.

Where the hedged item is a non-financial asset or liability, such as a forecast foreign currency transaction for the purchase of property, plant and equipment, the amounts recognized within other comprehensive income are reclassified to the initial carrying amount of the non-financial asset or liability. Where the hedged item is an equity investment, the amounts recognized in other comprehensive income remain in the separate component of equity until the hedged cash flows affect profit or loss. Where the hedged item is recognized directly in profit or loss, the amounts recognized in other comprehensive income are reclassified to production and manufacturing expenses, except for cash flow hedges of variable interest rate risk which are reclassified to finance costs.

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 reclassified to the income statement or to the initial carrying amount of a non-financial asset or liability as above.

Significant estimate or judgement: application of hedge accounting

The decision as to whether to apply hedge accounting within subsidiaries, and by equity-accounted entities, can have a significant impact on the group s financial statements. Cash flow and fair value hedge accounting is applied to certain finance debt-related instruments in the normal course of business and cash flow hedge accounting is applied to certain highly probable foreign currency transactions as part of the management of currency risk. 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. The group 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 in 2013 and a pre-tax gain of $1,410 million in 2012. See Note 15, Note 27, and Note 28 for further details.

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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

Significant estimate or judgement: valuation of derivatives

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, as well as to the majority of the group s embedded derivatives. These embedded derivatives arise primarily from long-term UK natural gas contracts that use pricing formulae not related to gas prices, for example, oil product and power prices. The majority of 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 28.

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. 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 are considered when assessing whether a current legally enforceable right to set off exists.

Provisions, contingencies and reimbursement assets

Provisions are recognized when the group has a present legal or constructive obligation 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. A provision is discounted using either a nominal discount rate of 2.75% (2013 3.25%) or a real discount rate of 0.75% (2013 1%), as appropriate. Provisions are split between amounts expected to be settled within 12 months of the balance sheet date (current) and amounts expected to be settled later (non-current). Contingent liabilities are possible obligations whose existence will only be confirmed by future events not wholly within the control of the group, or present obligations where it is not probable that an outflow of resources will be required or the amount of the obligation cannot be measured with sufficient reliability.

Contingent liabilities are not recognized in the financial statements but are disclosed unless the possibility of an outflow of economic resources is considered remote.

Where the group makes contributions into a separately administered fund for restoration, environmental or other obligations, which it does not control, and the group s right to the assets in the fund is restricted, the obligation to contribute to the fund is recognized as a liability where it is probable that such additional contributions will be made. The group recognizes a reimbursement asset separately, being the lower of the amount of the associated restoration, environmental or other provision and the group s share of the fair value of the net assets of the fund available to contributors.

Significant estimate or judgement: provision relating to the Gulf of Mexico oil spill

Detailed information on the Gulf of Mexico oil spill, including the financial impacts, is provided in Note 2.

The provision recognized is the reliable estimate of expenditures required to settle certain present obligations at the end of the reporting period. There are future expenditures, however, 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 the assumption that BP did not act with gross negligence or engage in wilful misconduct. However, in September 2014 the district court ruled that the discharge of oil was the result of BP s gross negligence and wilful misconduct and it is not now possible to determine a reliable estimate of the liability. The existing provision has been maintained as explained in Note 2 and a contingent liability has been disclosed in relation to the potential for a higher penalty due to this ruling. The amount that will become payable by BP is subject to a very high level of uncertainty since it will depend on the outcome of BP s appeal of the September 2014 gross negligence ruling as well as what is determined by the court in the federal multi-district litigation proceedings in New Orleans (MDL 2179) with respect to the application of statutory penalty factors. See Note 2 for additional information.

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. The provision for the costs of decommissioning wells, production facilities and pipelines at the end of their economic lives is estimated using existing technology, at current prices or future assumptions, depending on the expected timing of the activity, and discounted using the real discount rate. The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately

20 years.

An amount equivalent to the decommissioning provision is recognized as part of the corresponding intangible asset (in the case of an exploration or appraisal well) or property, plant and equipment. The decommissioning portion of the property, plant and equipment is subsequently depreciated at the same rate as the rest of the asset.

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1. Significant accounting policies, judgements, estimates and assumptions continued

Other than the unwinding of discount on the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding asset.

Environmental expenditures and liabilities

Environmental expenditures that are required in order for the group to obtain future economic benefits from its assets are capitalized as part of those assets. 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 to settle the obligation. Provisions for environmental liabilities have been estimated using existing technology, at current prices and discounted using a real discount rate. The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately five years.

Significant estimate or judgement: provisions

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 occurs are uncertain. Decommissioning technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. BP believes that the impact of any reasonably foreseeable change 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. 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 the 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 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 2014 was a real rate of 0.75% (2013 1.0%), which was based on long-dated US government bonds.

Provisions and contingent liabilities relating to the Gulf of Mexico oil spill are discussed in Note 2. Information about the group s other provisions is provided in Note 21. As further described in Note 21, 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.

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 balance sheet date 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. A corresponding credit is recognized within equity. Fair value is determined by using an appropriate, widely used, 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 any remaining unrecognized cost is expensed.

Cash-settled transactions

The cost of cash-settled transactions is recognized as an expense over the vesting period, measured by reference to the fair value of the corresponding liability which is recognized on the balance sheet. The liability is remeasured at fair value at each balance sheet date until settlement, with changes in fair value recognized in the income statement.

Pensions and other post-retirement benefits

The cost of providing benefits under the group s 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, which is recognized in the income statement, 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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

Remeasurements of the defined benefit liability and 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 and are not subsequently reclassified to profit and loss.

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. Defined benefit pension plan surpluses are only recognized to the extent they are recoverable.

Contributions to defined contribution plans are recognized in the income statement in the period in which they become payable.

Significant estimate or judgement: pensions and other post-retirement benefits

Accounting for pensions and other post-retirement benefits involves judgement about uncertain events, including estimated retirement dates, salary levels at retirement, mortality rates, determination of discount rates for measuring plan obligations and net interest expense and assumptions for inflation rates.

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.

The assumptions used are provided in Note 22.

The discount rate and inflation 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 22.

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 22.

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.

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 and associates and interests in joint arrangements, 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 and associates and interests in joint arrangements, 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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

Significant estimate or judgement: income taxes

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 7.

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 taxes 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 are shown as deductions from shareholders equity at cost. For accounting purposes, own equity instruments include both treasury shares and shares purchased from the open market. Some of these own equity instruments are held by Employee Share Ownership Plans (ESOPs), including certain shares transferred out of treasury. Consideration, if any, 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, but are shown as a deduction from the profit and loss account 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.

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.

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

There are no new or amended standards or interpretations adopted during the year that have a significant impact on the financial statements.

Not yet adopted

The following pronouncements from the IASB will become effective for future financial reporting periods and have not yet been adopted by the group.

The IASB issued IFRS 15 Revenue from Contracts with Customers , which provides a single model for accounting for revenue arising from contracts with customers and is effective for annual periods beginning on or after 1 January 2017. IFRS 15 will supersede IAS 18 Revenue .

The IASB has also issued IFRS 9 Financial Instruments , which will supersede IAS 39 Financial Instruments: Recognition and Measurement and is effective for annual periods beginning on or after 1 January 2018. IFRS 9 covers classification and measurement of financial assets and financial liabilities, impairment methodology and hedge accounting.

BP has not yet decided the date of adoption for the group for IFRS 15 and IFRS 9 and has not yet completed its evaluation of the effect of adoption. The EU has not yet adopted IFRS 15 or IFRS 9.

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.

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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 $43.5 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 and the measurement of the penalty obligation under the Clean Water Act, 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 48 and Legal proceedings on page 228.

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
	2014	2013	2012
Income statement			
Production and manufacturing expenses	**781**	430	4,995
Profit (loss) before interest and taxation	**(781)**	(430)	(4,995)
Finance costs	**38**	39	19
Profit (loss) before taxation	**(819)**	(469)	(5,014)
Less: Taxation	**262**	73	94
Profit (loss) for the period	**(557)**	(396)	(4,920)
Balance sheet			
Current assets			
Trade and other receivables	**1,154**	2,457	
Current liabilities			
Trade and other payables	**(655)**	(1,030)	
Provisions	**(1,702)**	(2,951)	
Net current assets (liabilities)	**(1,203)**	(1,524)	
Non-current assets			
Other receivables	**2,701**	2,442	
Non-current liabilities			
Other payables	**(2,412)**	(2,986)	
Accruals	**(169)**		
Provisions	**(6,903)**	(6,395)	

Deferred tax	**1,723**	2,748	
Net non-current assets (liabilities)	**(5,060)**	(4,191)	
Net assets (liabilities)	**(6,263)**	(5,715)	
Cash flow statement			
Profit (loss) before taxation	**(819)**	(469)	(5,014)
Finance costs	**38**	39	19
Net charge for provisions, less payments	**939**	1,129	4,834
(Increase) decrease in other current and non-current assets	**(662)**	(1,481)	(998)
Increase (decrease) in other current and non-current liabilities	**(792)**	(618)	(5,090)
Pre-tax cash flows	**(1,296)**	(1,400)	(6,249)

The impact on net cash provided by operating activities, on a post-tax basis, amounted to an outflow of $9 million (2013 outflow of $73 million and 2012 outflow of $2,382 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) 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 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

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2. Significant event Gulf of Mexico oil spill continued

payments will be made directly from the trust fund, and BP will be released from its corresponding obligation. The reimbursement asset is recorded within Trade and other receivables on the balance sheet apportioned between current and non-current elements. The net increase in the provision for items covered by the trust fund of $662 million relates principally to business economic loss claims as well as increases in the provision for claims administration costs. During the year, cumulative charges to be paid by the Trust reached $20 billion. Subsequent additional costs, over and above those provided within the $20 billion, are being expensed to the income statement as incurred.

At 31 December 2014, $3,855 million of the provisions and payables are eligible to be paid from the Trust. The table below shows movements in the reimbursement asset during the period to 31 December 2014.

$ million

		2014	2013	Cumulative since the incident
At 1 January		**4,899**	6,442	
Net Increase in provision for items covered by the trust fund		**662**	1,542	20,000
Amounts paid directly by the trust fund		**(1,706)**	(3,085)	(16,145)
At 31 December		**3,855**	4,899	3,855
Of which	current	**1,154**	2,457	1,154
	non-current	**2,701**	2,442	2,701

As at 31 December 2014, the aggregate cash balances in the Trust and the QSFs amounted to $5.1 billion, including $1.1 billion remaining in the seafood compensation fund which has yet to be distributed and $0.4 billion held for natural resource damage early restoration. A further $500-million partial distribution from the seafood compensation fund has been recommended and disbursement of funds commenced in early 2015. The portion of the provision and reimbursement asset that related to the seafood compensation fund were derecognized upon funding of the seafood compensation fund QSF in 2012.

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. 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 228.

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 agreed to pay $4 billion over a period of five years. At 31 December 2014, the remaining criminal claims payable, within Other payables, was $2,995 million, of which $595 million falls due in 2015.

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, with the final instalment paid during 2014.

Provisions and contingent liabilities

Provisions

BP has recorded provisions relating to the Gulf of Mexico oil spill in relation to environmental expenditure (including 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 2014
	Environmental	Litigation and Claims	Clean Water Act	Total
At 1 January	1,679	4,157	3,510	9,346
Increase in provision	190	1,137		1,327
Unwinding of discount	1			1
Change in discount rate	2			2
Utilization paid by BP	(83)	(307)		(390)
paid by the trust fund	(648)	(1,033)		(1,681)
At 31 December	1,141	3,954	3,510	8,605
Of which current	528	1,174		1,702
non-current	613	2,780	3,510	6,903

				$ million Cumulative since the incident
	Environmental	Litigation and Claims	Clean Water Act	Total
Net increase in provision	14,599	26,595	3,510	44,704
Unwinding of discount	13	6		19
Change in discount rate	19			19
Reclassified to other payables		(4,283)		(4,283)
Utilization paid by BP	(11,687)	(4,080)		(15,767)
paid by the trust fund	(1,803)	(14,284)		(16,087)
At 31 December 2014	1,141	3,954	3,510	8,605

Environmental

The environmental provision at 31 December 2014 includes the remaining $279 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

2. Significant event Gulf of Mexico oil spill continued

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 into 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 and during 2014, Phase 3 of the early restoration projects was formally agreed, comprising $627 million of approved project spend (of which $563 million has been paid). At 31 December 2014, the remaining amount provided for natural resource damage assessment costs and early restoration projects was $798 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.

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, under OPA 90 and other legislation (State and Local Claims), except as described under Contingent liabilities below. Claims administration costs and legal costs, including legal costs under indemnification agreements, have also been provided for. The timing of payment of litigation and claims provisions classified as non-current is dependent upon ongoing 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, which are provided for where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility. As disclosed in *BP Annual Report and Form 20-F 2013*, 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 Economic and Property Damages Settlement Agreement (EPD Settlement Agreement) by the claims administrator that BP believes was incorrect.

During 2014, there were various rulings 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.

In March 2014, the US Court of Appeals for the Fifth Circuit (the Fifth Circuit) affirmed the district court s ruling that the EPD Settlement Agreement contained no causation requirement beyond the revenue and related tests set out in an exhibit to that agreement. In March 2014, BP filed a petition that all the active judges of the Fifth Circuit review the decision; in May 2014 this was denied. The district court dissolved the injunction that had halted the processing and payment of business economic loss claims and instructed the claims administrator to resume the processing and payment of claims. BP sought review by the US Supreme Court (Supreme Court) of the Fifth Circuit s decisions relating to compensation of claims for losses with no apparent connection to the Deepwater Horizon spill. In December 2014, the Supreme Court declined to review BP s petition. As a result, the final deadline for filing claims in the Economic and Property Damages Settlement is 8 June 2015.

Management believes that no reliable estimate can currently be made of any business economic loss claims (i) not yet received; (ii) received, but not yet processed; or (iii) processed, but not yet paid, except where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility. The inability to estimate reliably such claims is due to uncertainty regarding both the volume of such claims and the average value per claim.

In respect of uncertainty regarding the volume of claims, in December 2014, the Supreme Court declined to hear BP s appeal of the district court ruling that the EPD Settlement Agreement contained no causation requirement beyond the revenue and related tests set forth in that agreement. This resolution, however, does not reduce uncertainty in the short term regarding the volume of claims, since it is possible that additional claims will be made. In addition, a claims submission deadline of 8 June 2015 has now been set, which may lead to an increase in the rate of claims received until the deadline, compounding management s inability to estimate the total volume of claims that will be made.

In respect of uncertainty regarding the average value per claim, a small proportion of the filed claims have been determined under the revised policy for the matching of revenue and expenses for business economic loss claims (introduced in May 2014) and disputes, disagreements, and uncertainties regarding the proper application of the revised policy to particular claims and categories of claims continue to arise as the claims administrator has begun applying the revised policy. Furthermore, there have been no, or only a small number of, claim determinations made under some of the specialized frameworks that have been put in place for particular industries and so determinations to date may not be representative of the total population of claims. In addition, due to a data secrecy order, detailed data about claims that have not yet been determined is not currently available to BP and so it is not possible to review claim demographics or identify potential populations for each category of claim.

There is therefore very little data to build up a track record of claims determinations under the policies and protocols that are now being applied following resolution of the matching and causation issues. We therefore cannot estimate future trends of the number and proportion of claims that will be determined to be eligible, nor can we estimate the value of such claims. A provision for such business economic loss claims will be established when these uncertainties are resolved and a reliable estimate can be made of the liability.

The current estimate for the total cost of those elements of the PSC settlement that BP considers can be reliably estimated is $9.9 billion. The DHCSSP has issued eligibility notices, most of which are disputed by BP, in respect of business economic loss claims of approximately $400 million which have not been provided for. The majority of these claims are being re-assessed using the new matching policy. 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 total cost of the PSC settlement is likely to be significantly higher than the amount recognized to date of $9.9 billion because the current estimate does not reflect business economic loss claims not yet received, or received but not yet processed, or processed but not yet paid, except where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility.

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.

Significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable, including claims payable under the DHCSSP and State and Local Claims. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported as described above and in Legal proceedings on page 228 and the outcomes of any further litigation including in relation to potential opt-outs from the PSC settlement or otherwise. There is also uncertainty as to the cost of administering the claims process under the DHCSSP and in relation to future legal costs.

See Legal proceedings on page 228 and Contingent liabilities below for further details.

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2. Significant event Gulf of Mexico oil spill continued

Clean Water Act penalties

A provision of $3,510 million was recognized in 2010 for estimated civil penalties under Section 311 of the Clean Water Act. At the time the provision for the Clean Water Act penalty was made, the number of barrels of oil spilled was determined by using the mid-point (47,500 barrels per day) of the range of estimates (35,000 to 60,000 barrels per day) from the intra-agency Flow Rate Technical Group created by the National Incident Commander in charge of the spill response. The initial 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.

The estimates of cumulative discharge presented by experts testifying in the Phase 2 trial varied significantly. In January 2015, the district court issued its decision in the Phase 2 trial that 3.19 million barrels of oil were discharged into the Gulf of Mexico and therefore subject to a Clean Water Act penalty. This amount is consistent with the number of barrels BP has used to calculate the provision. In addition, the district court found that BP was not grossly negligent in its source control efforts. BP and other parties to the proceedings have filed notices of appeal of the Phase 2 ruling and therefore the findings from the Phase 2 trial remain subject to uncertainty.

In September 2014, the district court issued its decision in the Phase 1 trial that the discharge of oil was the result of the gross negligence and wilful misconduct of BP Exploration & Production Inc. (BPXP) and that BPXP is therefore subject to enhanced civil penalties. The statutory maximum penalty is up to $4,300 per barrel of oil discharged where gross negligence or wilful misconduct is proven. BP does not believe that the evidence at trial supports a finding of gross negligence and wilful misconduct and in December 2014 filed notice of appeal of the Phase 1 ruling.

As a result of the September 2014 district court ruling that the discharge of oil was the result of BP s gross negligence and wilful misconduct, the Clean Water Act penalty obligation is not considered to be reliably measurable and it is therefore no longer possible to determine a best estimate of the Clean Water Act penalty provision. Under IFRS, a provision is reversed when it is no longer probable that an outflow of resources will be required to settle the obligation. With regard to the Clean Water Act penalty obligation, it continues to be probable that there will be an outflow of resources and therefore, in the absence of the ability to identify the best estimate of the liability, the previously recognized provision of $3,510 million has been maintained. Note 1 Provisions, contingencies and reimbursement assets identifies the significant accounting estimates and judgements made in relation to the Clean Water Act provision.

BP continues to believe that a provision of $3,510 million represents a reliable estimate of the amount of the liability if the appeal is successful. If BP is unsuccessful in its appeal, and the ruling of gross negligence and wilful misconduct is upheld, the maximum penalty that could be imposed is up to $4,300 per barrel. Based upon this penalty rate and the district court s ruling on the number of barrels spilled, which, as noted above is also subject to appeal, the maximum penalty could be up to $13.7 billion.

However, in assessing the amount of the penalty, the court is directed to consider the following statutory penalty factors: 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 . The court has wide discretion in deciding how to apply these factors to determine the penalty and what weighting to ascribe to different factors. BP is therefore unable to ascribe probabilities to possible outcomes within the range of potential penalties and cannot determine a reliable estimate for any additional penalty which might apply should the gross negligence finding be upheld. The trial phase to determine the amount of the Clean Water Act penalty commenced on 20 January 2015.

The amount that may become payable by BP is subject to a very high level of uncertainty since it will depend on the outcome of BP s appeals as well as what is determined by the district court with respect to the application of statutory penalty factors as noted above. The court has wide discretion in the application of statutory penalty factors. The timing of any payment is also uncertain.

Given the significant uncertainty, the very wide range of possible outcomes if BP is unsuccessful in this appeal of the September ruling, and the inability to ascribe probabilities to possible outcomes within the range, management is not able to estimate reliably any further liability for the Clean Water Act penalty arising in the event that BP is not successful in its appeal. A contingent liability is therefore disclosed. See Contingent liabilities below for further information.

Provision movements

The total amount recognized as an increase in provisions during the year was $1,327 million. After deducting amounts utilized during the year totalling $2,071 million, including payments from the trust fund of $1,681 million and payments made directly by BP of $390 million (2013 $3,777 million, including payments from the trust fund of $3,051 million and payments made directly by BP of $726 million), and after adjustments for discounting, the remaining provision as at 31 December 2014 was $8,605 million (2013 $9,346 million).

The total amounts that will ultimately be paid by BP for 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, 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 that can be measured reliably. It is not possible, at this time, to measure reliably other obligations arising from the incident, 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 2014.

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2. Significant event Gulf of Mexico oil spill continued

Natural resource damage claims

As described above in Provisions, a provision has been made for natural resource damage assessment and early restoration projects under the $1-billion framework agreement. 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 damage claims and associated legal costs, therefore no such amounts have been provided as at 31 December 2014.

Business economic loss claims under the PSC settlement

BP 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. The potential cost of business economic loss claims not yet received, processed and paid (except where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility) 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. See Provisions above for further information.

State and Local claims

As described above in Provisions, a provision has been made for State and Local claims that can be measured reliably. The States of Alabama, Mississippi, Florida, Louisiana and Texas 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. 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. 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; the timing of any outflow of resources in relation to State and Local claims is dependent on the timing of the court process in relation to these claims.

Clean Water Act penalties

A provision has been maintained for BP s obligation under the Clean Water Act, as described above in Provisions. Any obligation in relation to any further liability for the Clean Water Act penalty arising in the event that BP is not successful in its appeal of the Phase 1 ruling is disclosed as a contingent liability. The trial phase to determine the amount of the Clean Water Act penalty commenced in January 2015 and post-trial briefing is scheduled to complete in April 2015. BP does not know when the district court will rule on the Penalty Phase of the trial and so the timing of any payment continues to be uncertain.

Securities-related litigation

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 Depositary Shares under US federal securities law, are continuing. A jury trial is scheduled to begin in January 2016 and the timing of any outflow of resources, if any, is dependent on the duration of the court process. 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 2014. In addition, no reliable estimate can be made of the amounts that may be payable in relation to any other securities litigation, if any, so no provision has been recognized at 31 December 2014.

Other litigation

In addition to the State and Local claims and securities class actions described above, BP is named as a defendant in approximately 3,000 other civil lawsuits brought by individuals, corporations and government entities in US federal and state courts, as well as certain non-US 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. In addition, claims have been received, primarily from business claimants, under OPA 90 in relation to the 2010 federal deepwater drilling moratoria. 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, nor it is possible to determine the timing of any payment that may arise. Therefore no amounts have been provided for these items as at 31 December 2014.

It is not possible to measure reliably any obligation in relation to other litigation or potential fines and penalties. 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.

Settlement and other agreements

Under the settlement agreements with Anadarko and MOEX, and with Cameron International, the designer and manufacturer of the Deepwater Horizon blowout preventer, BP has agreed to indemnify Anadarko, MOEX and Cameron 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, nor identify the timing of, any obligation in relation to such claims and therefore no amount has been provided as at 31 December 2014. There are also agreements indemnifying certain third-party contractors in relation to litigation costs and certain other claims. A contingent liability is also disclosed in relation to other obligations under these agreements.

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 48. 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.

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2. Significant event Gulf of Mexico oil spill continued

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

	2014	2013	2012	Cumulative since the incident
Net increase in provision	**1,327**	1,860	6,074	44,705
Change in discount rate relating to provisions	**2**	(5)		19
Costs charged directly to the income statement	**114**	136	257	4,358
Trust fund liability discounted				19,580
Change in discounting relating to trust fund liability				283
Recognition of reimbursement asset, net	**(662)**	(1,542)	(1,191)	(20,000)
Settlements credited to the income statement		(19)	(145)	(5,681)
(Profit) loss before interest and taxation	**781**	430	4,995	43,264
Finance costs	**38**	39	19	231
(Profit) loss before taxation	**819**	469	5,014	43,495

The group income statement for 2014 includes a pre-tax charge of $819 million (2013 pre-tax charge of $469 million) in relation to the Gulf of Mexico oil spill. The costs charged in 2014 relate primarily to the ongoing costs of operating the Gulf Coast Restoration Organization (GCRO) and increases in the provisions for natural resource damage assessment, business economic loss claims, claims administration costs, legal and litigation costs. Finance costs of $38 million (2013 $39 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 and estimated obligations for future costs that can be estimated reliably at this time, 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

	2014	2013	2012	Cumulative since the incident
Trust fund liability discounted				19,580
Change in discounting relating to trust fund liability				283
Recognition of reimbursement asset, net	**(662)**	(1,542)	(1,191)	(20,000)
Other				8
Total (credit) charge relating to the trust fund	**(662)**	(1,542)	(1,191)	(129)
Environmental amount provided	**190**	47	801	3,134
change in discount rate relating to provisions	**2**	(5)		19
costs charged directly to the income statement				70
Total (credit) charge relating to environmental	**192**	42	801	3,223

Spill response amount provided		(113)	109	11,465
costs charged directly to the income statement			9	2,839
Total (credit) charge relating to spill response		(113)	118	14,304
Litigation and claims amount provided, net of provision derecognized	**1,137**	1,926	5,164	26,596
costs charged directly to the income statement				184
Total charge relating to litigation and claims	**1,137**	1,926	5,164	26,780
Clean Water Act penalties amount provided				3,510
Other costs charged directly to the income statement	**114**	136	248	1,257
Settlements credited to the income statement		(19)	(145)	(5,681)
(Profit) loss before interest and taxation	**781**	430	4,995	43,264
Finance costs	**38**	39	19	231
(Profit) loss before taxation	**819**	469	5,014	43,495

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.

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3. Disposals and impairment

The following amounts were recognized in the income statement in respect of disposals and impairments.

			$ million
	2014	2013	2012
Gains on sale of businesses and fixed assets			
Upstream	**405**	371	6,504
Downstream	**474**	214	152
TNK-BP		12,500	
Other businesses and corporate	**16**	30	41
	895	13,115	6,697

			$ million
	2014	2013	2012
Losses on sale of businesses and fixed assets			
Upstream	**345**	144	109
Downstream	**401**	78	195
Other businesses and corporate	**3**	8	6
	749	230	310
Impairment losses			
Upstream	**6,737**	1,255	3,046
Downstream	**1,264**	484	2,892
Other businesses and corporate	**317**	218	320
	8,318	1,957	6,258
Impairment reversals			
Upstream	**(102)**	(226)	(289)
Downstream			(1)
Other businesses and corporate			(3)
	(102)	(226)	(293)
Impairment and losses on sale of businesses and fixed assets	**8,965**	1,961	6,275

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. By 31 December 2012, the group had announced disposals of $38 billion, and in addition, announced the sale of our 50% investment in TNK-BP. During 2013, the group announced that it expected to divest a further $10 billion of assets before the end of 2015. BP had agreed around $4.7 billion of such further divestments and received proceeds of $3.6 billion as at 31 December 2014.

			$ million
	2014	2013	2012

Proceeds from disposals of fixed assets	**1,820**	18,115	9,992
Proceeds from disposals of businesses, net of cash disposed	**1,671**	3,884	1,606
	3,491	21,999	11,598
By business			
Upstream	**2,533**	1,288	10,667
Downstream	**864**	3,991	637
TNK-BP		16,646	
Other businesses and corporate	**94**	74	294
	3,491	21,999	11,598

At 31 December 2014, deferred consideration relating to disposals amounted to $1,137 million receivable within one year (2013 $23 million and 2012 $24 million) and $333 million receivable after one year (2013 $1,374 million and 2012 $1,433 million). In addition, contingent consideration relating to the disposals of the Devenick field and the Texas City refinery amounted to $454 million at 31 December 2014 (2013 $953 million) see Notes 16 and 28 for further information.

Upstream

In 2014, gains principally resulted from the sale of certain onshore assets in the US, and the sale of certain interests in the Gulf of Mexico and the North Sea. Losses principally arose from adjustments to prior year disposals in Canada and the North Sea.

In 2013, gains principally resulted from the sale of certain of our interests in the central North Sea, and the Yacheng field in China.

In 2012, gains principally resulted from the sale of certain interests in the Gulf of Mexico and certain onshore assets in the US, the sale of our interests in our Canadian natural gas liquids business, and the sale of a number of interests in the North Sea.

Downstream

In 2014, gains principally resulted from the disposal of our global aviation turbine oils business. Losses principally arose from costs associated with the decision to cease refining operations at Bulwer Island in Australia.

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3. Disposals and impairment continued

In 2013, gains principally 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.

In 2012, gains principally resulted from the disposal of our interests in purified terephthalic acid production in Malaysia, and retail churn in the US. Losses principally resulted from costs associated with our US refinery divestments.

TNK-BP

In 2013, BP disposed of its 50% interest in TNK-BP to Rosneft, resulting in a gain on disposal of $12,500 million.

Summarized financial information relating to the sale of businesses is shown in the table below. The principal transaction categorized as a business disposal in 2014 was the sale of certain of our interests on the North Slope of Alaska in our upstream business, which had been classified as held for sale during 2014. 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
	2014	2013	2012
Non-current assets	**1,452**	2,124	610
Current assets	**182**	2,371	570
Non-current liabilities	**(395)**	(94)	(263)
Current liabilities	**(65)**	(62)	(232)
Total carrying amount of net assets disposed	**1,174**	4,339	685
Recycling of foreign exchange on disposal	**(7)**	23	(15)
Costs on disposal[a]	**128**	13	39
	1,295	4,375	709
Gains on sale of businesses	**280**	69	675
Total consideration	**1,575**	4,444	1,384
Consideration received (receivable)[b]	**96**	(414)	76
Proceeds from the sale of businesses related to completed transactions	**1,671**	4,030	1,460
Deposits received related to assets classified as held for sale			146
Disposals completed in relation to which deposits had been received in prior year		(146)	
Proceeds from the sale of businesses[c]	**1,671**	3,884	1,606

[a] 2013 includes pension and other post-retirement benefit plan curtailment gains of $109 million.

[b] 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.

[c] 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 $32 million (2013 $42 million and 2012 $4 million).

Impairments

Impairment losses in each segment are described below. For information on significant estimates and judgements made in relation to impairments see Impairment of property, plant and equipment, intangibles and goodwill within Note 1.

Upstream

The 2014 impairment losses of $6,737 million included $4,876 million in the North Sea business, of which $1,964 million related to the Valhall cash-generating unit (CGU), $660 million related to the Andrew area CGU, and $515 million related to the ETAP CGU. These CGUs have recoverable amounts of $767 million, $1,431 million, and $1,753 million respectively. Impairment losses also included an $859-million impairment of our PSVM CGU in Angola to its recoverable amount of $1,964 million, and a $415-million impairment of the Block KG D6 CGU in India to its recoverable amount of $2,364 million. The recoverable amount of the Block KG D6 CGU is stated after the exploration write-off described in Note 6. All of the impairments relate to producing assets. The impairments in the North Sea and Angola arose as a result of a lower price environment in the near term, technical reserves revisions, and increases in expected decommissioning cost estimates. The impairment of Block KG D6 arose following the introduction of a new formula for Indian gas prices. The recoverable amounts of the Valhall and Block KG D6 CGUs are their fair values less costs of disposal based on the present value of future cash flows, a level-3 valuation technique in the fair value hierarchy. The key assumptions in the tests were oil and natural gas prices, production volumes and the discount rate. The recoverable amounts of the Andrew area CGU, the ETAP CGU and the PSVM CGU are their values in use. See Impairment of property, plant and equipment, intangible assets and goodwill within Note 1 for further information on assumptions used for impairment testing. The discount rate used to determine the value in use of the PSVM CGU included the 2% premium for higher-risk countries as described in Note 1. A premium was not applied in determining the recoverable amount of the other CGUs.

The main elements of the 2013 impairment losses of $1,255 million were a $251-million impairment loss relating to the Browse project in Australia and a $253-million aggregate write-down of a number of assets in the North Sea, caused by increases in expected decommissioning costs. Impairment reversals arose on certain of our interests in Alaska, the Gulf of Mexico, and the North Sea, triggered by reductions in decommissioning provisions due to continued review of the expected decommissioning costs and an increase in the discount rate for provisions.

The main elements of the 2012 impairment losses of $3,046 million were a $1,082-million write-down of our interests in certain 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. Impairment reversals principally arose on certain of our interests in the Gulf of Mexico, triggered by a decision to divest assets.

Downstream

The main elements of the 2014 impairment losses of $1,264 million related to our Bulwer Island refinery and certain midstream assets in our fuels business, and certain manufacturing assets in our petrochemicals business.

The main elements of the 2013 impairment losses of $484 million related to impairments of certain refineries in the US and elsewhere in our global fuels portfolio.

The main elements of the 2012 impairment losses of $2,892 million related to assets held for sale for which sales prices had been agreed. This 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.

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3. Disposals and impairment continued

Other businesses and corporate

Impairment losses totalling $317 million, $218 million, and $320 million were recognized in 2014, 2013 and 2012 respectively. The amount for 2014 is principally in respect of our biofuels businesses in the UK and US. The amount for 2013 is principally in respect of our US wind business. The amount for 2012 is principally in respect of the decision not to proceed with an investment in a biofuels production facility under development in the US.

4. Segmental analysis

The group s organizational structure reflects the various activities in which BP is engaged. At 31 December 2014, 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 biofuels and wind businesses, the group s shipping and treasury functions, and corporate activities worldwide.

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. 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 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 group subsidiary which made the sale. 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 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 replacement cost of inventory 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 historical 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 based on the replacement cost of inventory. For this purpose, the replacement cost of inventory is calculated using data from each operation s production and manufacturing system, either on a monthly basis, or separately for each transaction where the system allows this approach. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions.

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4. Segmental analysis continued

$ million

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group 2014
Segment revenues							
Sales and other operating revenues	**65,424**	**323,486**		**1,989**		**(37,331)**	**353,568**
Less: sales and other operating revenues between segments	**(36,643)**	**173**		**(861)**		**37,331**	
Third party sales and other operating revenues	**28,781**	**323,659**		**1,128**			**353,568**
Equity-accounted earnings	**1,089**	**265**	**2,101**	**(83)**			**3,372**
Segment results							
Replacement cost profit (loss) before interest and taxation	**8,934**	**3,738**	**2,100**	**(2,010)**	**(781)**	**641**	**12,622**
Inventory holding gains (losses)[a]	**(86)**	**(6,100)**	**(24)**				**(6,210)**
Profit (loss) before interest and taxation	**8,848**	**(2,362)**	**2,076**	**(2,010)**	**(781)**	**641**	**6,412**
Finance costs							**(1,148)**
Net finance expense relating to pensions and other post-retirement benefits							**(314)**
Profit before taxation							**4,950**
Other income statement items							
Depreciation, depletion and amortization[b]							
US	**4,129**	**984**		**97**			**5,210**
Non-US	**8,404**	**1,336**		**213**			**9,953**
Fair value (gain) loss on embedded derivatives	**(430)**						**(430)**
Charges for provisions, net of write-back of unused provisions, including change in discount rate	**260**	**713**		**323**	**1,329**		**2,625**
Segment assets							
Equity-accounted investments	**7,877**	**3,244**	**7,312**	**723**			**19,156**
Additions to non-current assets[c]	**22,587**	**3,121**		**784**			**26,492**

Additions to other investments				**160**
Element of acquisitions not related to non-current assets				**(366)**
Additions to decommissioning asset				**(2,505)**
Capital expenditure and acquisitions	**19,772**	**3,106**	**903**	**23,781**

[a] See explanation of inventory holding gains and losses on page 119.

[b] It is estimated that the benefit arising from the absence of depreciation for the assets held for sale during the year was $221 million.

[c] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

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4. Segmental analysis continued

								$ million 2013
By business	Upstream	Downstream	Rosneft	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	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
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[b]								
US	3,538	747			181			4,466
Non-US	7,514	1,343			187			9,044
Fair value (gain) loss on embedded derivatives	(459)							(459)
Charges for provisions, net of	161	270			295	1,855		2,581

write-back of unused provisions, including change in discount rate					
Segment assets					
Equity-accounted investments	7,780	3,302	13,681	1,072	25,835
Additions to non-current assets[c]	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 119.

[b] 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.

[c] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

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4. Segmental analysis continued

							$ million
							2012
By business	Upstream	Downstream	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
Segment revenues							
Sales and other operating revenues	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
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[b]							
US	3,437	586		213			4,236
Non-US	6,918	1,343		190			8,451
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[c]	22,603	5,246		1,419			29,268
Additions to other investments							33
							(72)

Element of acquisitions not related to non-current assets						
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 119.

[b] It is estimated that the benefit arising from the absence of depreciation for the assets held for sale amounted to approximately $435 million.

[c] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

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4. Segmental analysis continued

By geographical area	US	Non-US	$ million 2014 Total
Revenues			
Third party sales and other operating revenues[a]	**122,951**	**230,617**	**353,568**
Other income statement items			
Production and similar taxes	**690**	**2,268**	**2,958**
Results			
Replacement cost profit before interest and taxation	**5,251**	**7,371**	**12,622**
Non-current assets			
Non-current assets[b c]	**69,125**	**114,462**	**183,587**
Capital expenditure and acquisitions	**7,227**	**16,554**	**23,781**

[a] Non-US region includes UK $77,522 million.
[b] Non-US region includes UK $18,430 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

By geographical area	US	Non-US	$ million 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			
Non-current assets[b c]	70,228	124,439	194,667
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] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

By geographical area	US	Non-US	$ million 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			
Non-current assets[b c]	66,751	107,844	174,595
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] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

5. Income statement analysis

			$ million
	2014	2013	2012
Currency exchange losses charged to the income statement[a]	**36**	180	106
Expenditure on research and development	**663**	707	674
Finance costs			
Interest payable	**1,025**	1,082	1,234
Capitalized at 1.94% (2013 2% and 2012 2.25%)[b]	**(185)**	(238)	(390)
Unwinding of discount on provisions and other payables	**308**	224	228
	1,148	1,068	1,072

[a] Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.
[b] Tax relief on capitalized interest is approximately $43 million (2013 $62 million and 2012 $93 million).
Interest and other income of $1,677 million in 2012 includes $709 million of dividends from TNK-BP.

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6. 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.

For information on significant estimates and judgements made in relation to oil and natural gas accounting see Intangible assets within Note 1.

			$ million
	2014	2013	2012
Exploration and evaluation costs			
Exploration expenditure written off[a]	**3,029**	2,710	745
Other exploration costs	**603**	731	730
Exploration expense for the year	**3,632**	3,441	1,475
Impairment losses		253	
Impairment reversals			(42)
Intangible assets exploration and appraisal expenditure	**19,344**	20,865	23,434
Liabilities	**227**	212	287
Net assets	**19,117**	20,653	23,147
Capital expenditure	**2,870**	4,464	5,176
Net cash used in operating activities	**603**	731	730
Net cash used in investing activities	**2,786**	4,275	5,010

[a] 2014 included a $544-million write-off relating to disappointing appraisal results of Utica shale in the US Lower 48 and the subsequent decision not to proceed with its development plans, a $524-million write-off relating to the Bourarhat Sud block licence in the Illizi Basin of Algeria, a $395-million write-off relating to Block KG D6 in India and a $295-million write-off relating to the Moccasin discovery in the deepwater Gulf of Mexico. 2013 included a $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 and 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 26.

The carrying amount, by location, of exploration and appraisal expenditure capitalized as intangible assets at 31 December 2014 is shown in the table below.

Carrying amount	Location
$1-2 billion	Angola; India
$2-3 billion	Canada; Egypt; Brazil
$4-5 billion	US Gulf of Mexico

7. Taxation

Tax on profit

			$ million
	2014	2013	2012
Current tax			
Charge for the year	**4,444**	5,724	6,664
Adjustment in respect of prior years	**48**	61	252
	4,492	5,785	6,916
Deferred tax			
Origination and reversal of temporary differences in the current year	**(3,194)**	529	67
Adjustment in respect of prior years	**(351)**	149	(103)
	(3,545)	678	(36)
Tax charge on profit	**947**	6,463	6,880

In 2014, the total tax credit recognized within other comprehensive income was $1,481 million (2013 $1,374 million charge and 2012 $270 million credit). See Note 30 for further information. The total tax charge recognized directly in equity was $36 million (2013 $33 million credit and 2012 $6 million credit).

For information on significant estimates and judgements made in relation to taxation see Income taxes within Note 1.

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 2014 the UK statutory corporation tax rate reduced from 23% to 21% on profits arising from activities outside the North Sea. For 2014, the items presented in the reconciliation are distorted as a result of the tax credits related to the impairment losses recognized in the year, and the effect of the impairment losses on the profit for the year. In order to provide a more meaningful analysis of the effective tax rate for 2014, the table also presents separate reconciliations for the group excluding the effects of the impairment losses, and for the effects of the impairment losses in isolation. For 2013 and 2012, the effective tax rate is not affected significantly by impairment losses. See Note 3 for further information.

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7. Taxation continued

$ million

	2014 excluding impairments	2014 impacts of impairments	2014	2013	2012
Profit (loss) before taxation	**13,166**	**(8,216)**	**4,950**	30,221	18,131
Tax charge (credit) on profit or loss	**5,036**	**(4,089)**	**947**	6,463	6,880
Effective tax rate	**38%**	**50%**	**19%**	21%	38%
			% of profit before taxation		
UK statutory corporation tax rate	**21**	**21**	**21**	23	24
Increase (decrease) resulting from					
UK supplementary and overseas taxes at higher or lower rates[a]	**17**	**34**	**(11)**	4	12
Tax reported in equity-accounted entities	**(5)**		**(14)**	(2)	(5)
Adjustments in respect of prior years	**(2)**		**(6)**	1	1
Movement in deferred tax not recognized	**4**	**(3)**	**17**	2	2
Tax incentives for investment	**(4)**		**(10)**	(2)	(2)
Gulf of Mexico oil spill non-deductible costs			**1**		8
Permanent differences relating to disposals[b]	**(1)**		**(1)**	(8)	
Foreign exchange	**4**		**10**	2	(1)
Items not deductible for tax purposes	**4**	**(2)**	**12**	1	2
Other					(3)
Effective tax rate	**38**	**50**	**19**	21	38

[a] For 2014 excluding impairments, jurisdictions which contribute significantly to this item are Angola, with an applicable statutory tax rate of 50%, Trinidad, with an applicable statutory tax rate of 55% and the US with an applicable federal tax rate of 35%. For 2014, impairment charges have generated losses on which tax credits arise, mainly in Norway and the UK North Sea, with applicable statutory tax rates of 78% and 62% respectively. For 2013 and 2012, jurisdictions which contribute significantly are Angola, the UK and Trinidad with rates as disclosed above.

[b] For 2013, this relates to the non-taxable gain on disposal of our investment in TNK-BP.

Legislation to reduce the UK supplementary charge tax rate applicable to profits arising in the North Sea is expected to be enacted in 2015. The evaluation of the effect of this change for BP has not yet been completed.

Deferred tax

$ million

	Income statement			Balance sheet	
	2014	2013	2012	**2014**	2013
Deferred tax liability					
Depreciation	**(2,178)**	(474)	(75)	**29,062**	31,551

Pension plan surpluses	**(272)**	(691)			284
Other taxable temporary differences	**(1,278)**	(199)	(2,239)	**2,445**	3,653
	(3,728)	(1,364)	(2,314)	**31,507**	35,488
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**492**	787	(33)	**(2,761)**	(2,026)
Decommissioning, environmental and other provisions	**52**	1,385	1,872	**(11,237)**	(11,301)
Derivative financial instruments	**166**	30	(7)	**(575)**	(579)
Tax credits	**589**	(174)	1,802	**(298)**	(888)
Loss carry forward	**(1,397)**	(343)	(911)	**(3,848)**	(2,585)
Other deductible temporary differences	**281**	357	(445)	**(1,204)**	(1,655)
	183	2,042	2,278	**(19,923)**	(19,034)
Net deferred tax charge (credit) and net deferred tax liability	**(3,545)**	678	(36)	**11,584**	16,454
Of which deferred tax liabilities				**13,893**	17,439
deferred tax assets				**2,309**	985

The recognition of deferred tax assets of $1,467 million (2013 $67 million), in entities which have suffered a loss in either the current or preceding period, is supported by forecasts which indicate that sufficient future taxable profits will be available to utilize such assets.

		$ million
Analysis of movements during the year in the net deferred tax liability	**2014**	2013
At 1 January	**16,454**	14,369
Exchange adjustments	**122**	43
Charge (credit) for the year on profit	**(3,545)**	678
Charge (credit) for the year in other comprehensive income	**(1,563)**	1,397
Charge (credit) for the year in equity	**36**	(33)
Acquisitions	**80**	
At 31 December	**11,584**	16,454

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7. Taxation continued

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	**2014**	2013
Unused tax losses[a]	**2.1**	1.8
Unused tax credits	**20.1**	18.0
of which arising in the UK[b]	**18.0**	16.3
arising in the US[c]	**2.0**	1.7
Deductible temporary differences[d]	**17.9**	11.2
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities[e]	**1.0**	1.1

[a] Substantially all the tax losses have no fixed expiry date.

[b] The UK unused 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 unused tax credits expire 10 years after generation and will all expire in the period 2015-2023.

[d] Deductible temporary differences of $1.0 billion are expected to expire in the period 2015-2021, the remainder do not have an expiry date.

[e] An amendment has been made to the comparative amount.

			$ billion
Impact of previously unrecognized deferred tax or write-down of deferred tax assets on current year charge	**2014**	2013	2012
Current tax benefit relating to the utilization of previously unrecognized tax credits	**0.2**	0.2	0.4
Deferred tax benefit relating to the recognition of previously unrecognized tax credits		0.2	0.1
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	**0.2**		

8. Dividends

The quarterly dividend expected to be paid on 27 March 2015 in respect of the fourth quarter 2014 is 10.00 cents per ordinary share ($0.60 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 16 March 2015. 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
	2014	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Dividends announced and paid in cash									
Preference shares							**2**	2	2
Ordinary shares									
March	**5.7065**	6.0013	5.0958	**9.50**	9.00	8.00	**1,426**	1,621	1,211
June	**5.8071**	5.8342	5.1498	**9.75**	9.00	8.00	**1,572**	1,399	1,448
September	**5.9593**	5.7630	5.0171	**9.75**	9.00	8.00	**1,122**	1,245	1,417
December	**6.3769**	5.8008	5.5890	**10.00**	9.50	9.00	**1,728**	1,174	1,216
	23.8498	23.3993	20.8517	**39.00**	36.50	33.00	**5,850**	5,441	5,294
Dividend announced, payable in March 2015				**10.00**			**1,817**		

The details of the scrip dividends issued are shown in the table below.

	2014	2013	2012
Number of shares issued (thousand)	**165,644**	202,124	138,406
Value of shares issued ($ million)	**1,318**	1,470	982

The financial statements for the year ended 31 December 2014 do not reflect the dividend announced on 3 February 2015 and expected to be paid in March 2015; this will be treated as an appropriation of profit in the year ended 31 December 2015.

9. Earnings per ordinary share

			Cents per share
	2014	2013	2012
Basic earnings per share	**20.55**	123.87	57.89
Diluted earnings per share	**20.42**	123.12	57.50

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 certain shares that will be issuable in the future under employee share-based payment plans and treasury shares, which includes shares held by the Employee Share Ownership Plan trusts (ESOPs).

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
	2014	2013	2012
Profit attributable to BP shareholders	**3,780**	23,451	11,017
Less: dividend requirements on preference shares	**2**	2	2
Profit for the year attributable to BP ordinary shareholders	**3,778**	23,449	11,015

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9. Earnings per ordinary share continued

			Shares thousand
	2014	2013	2012
Basic weighted average number of ordinary shares	**18,385,458**	18,931,021	19,027,929
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**111,836**	115,152	129,959
	18,497,294	19,046,173	19,157,888

The number of ordinary shares outstanding at 31 December 2014, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 18,199,882,744. Between 31 December 2014 and 17 February 2015, the latest practicable date before the completion of these financial statements, there was a net decrease of 24,096,712 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, no further shares were repurchased following the continuation of share buybacks announced on 29 April 2014.

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 pages 72 88.

The following table shows the number of shares potentially issuable under equity-settled 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 these plans at 31 December included in the diluted earnings per share is also shown.

Share options		**2014**		2013
	Number of options[a b] thousand	**Weighted average exercise price $**	Number of options[a b] thousand	Weighted average exercise price $
Outstanding	**113,206**	**9.62**	286,725	7.71
Exercisable	**86,211**	**10.89**	127,290	10.01
Dilutive effect	**5,570**	**n/a**	23,169	n/a

[a] Numbers of options shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).
[b] At 31 December 2014 the quoted market price of one BP ordinary share was $6.35 (2013 $8.10).

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.

Share plans	**2014**	2013
	Number of shares[a]	Number of shares[a]
Vesting	**thousand**	thousand
Within one year	**78,467**	35,442
1 to 2 years	**91,993**	120,056
2 to 3 years	**80,966**	115,387
3 to 4 years	**28,564**	14,231
4 to 5 years	**222**	123
	280,212	285,239
Dilutive effect	**99,917**	95,014

[a] Numbers of shares shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).

There has been a net increase of 31,318,880 in the number of potential ordinary shares in relation with employee share-based payment plans between 31 December 2014 and 17 February 2015.

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10. Property, plant and equipment

$ million

	Land and land improvements	Buildings	Oil and gas properties[a]	Plant, machinery and equipment	Fixtures, fittings and office equipment	Transportation	Oil depots, storage tanks and service stations	Total
Cost								
At 1 January 2014	**3,375**	**3,027**	**187,691**	**48,912**	**3,176**	**13,314**	**9,961**	**269,456**
Exchange adjustments	**(284)**	**(105)**		**(1,737)**	**(93)**	**(44)**	**(871)**	**(3,134)**
Additions	**315**	**183**	**18,033**	**2,008**	**258**	**1,049**	**521**	**22,367**
Acquisitions	**31**	**22**		**252**	**3**			**308**
Transfers			**993**					**993**
Deletions	**(22)**	**(66)**	**(6,203)**	**(620)**	**(313)**	**(500)**	**(565)**	**(8,289)**
At 31 December 2014	**3,415**	**3,061**	**200,514**	**48,815**	**3,031**	**13,819**	**9,046**	**281,701**
Depreciation								
At 1 January 2014	**550**	**1,141**	**97,063**	**20,378**	**1,970**	**8,833**	**5,831**	**135,766**
Exchange adjustments	**(5)**	**(46)**		**(989)**	**(56)**	**(27)**	**(550)**	**(1,673)**
Charge for the year	**84**	**156**	**11,728**	**1,833**	**267**	**343**	**448**	**14,859**
Impairment losses	**15**		**6,304**	**625**		**179**	**504**	**7,627**
Impairment reversals			**(19)**			**(83)**		**(102)**
Deletions	**(5)**	**(54)**	**(3,901)**	**(489)**	**(198)**	**(312)**	**(509)**	**(5,468)**
At 31 December 2014	**639**	**1,197**	**111,175**	**21,358**	**1,983**	**8,933**	**5,724**	**151,009**
Net book amount at 31 December 2014	**2,776**	**1,864**	**89,339**	**27,457**	**1,048**	**4,886**	**3,322**	**130,692**
Cost								
At 1 January 2013	3,279	2,812	171,772	45,200	3,346	13,436	9,629	249,474
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	9,961	269,456
Depreciation								
At 1 January 2013	514	1,023	87,965	18,628	2,119	8,409	5,485	124,143
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	5,831	135,766
Net book amount at 31 December 2013	2,825	1,886	90,628	28,534	1,206	4,481	4,130	133,690

Assets held under finance leases at net book amount included above							
At 31 December 2014	**3**	**135**	**295**		**244**		**677**
At 31 December 2013	7	187	265		4		463
Assets under construction included above							
At 31 December 2014							**26,429**
At 31 December 2013							27,900

[a] For information on significant estimates and judgements made in relation to the estimation of oil and natural reserves see Property, plant and equipment within Note 1.

11. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2014 amounted to $15,635 million (2013 $13,705 million).

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12. Goodwill and impairment review of goodwill

		$ million
	2014	2013
Cost		
At 1 January	**12,851**	12,804
Exchange adjustments	**(278)**	46
Acquisitions	**73**	44
Deletions	**(164)**	(43)
At 31 December	**12,482**	12,851
Impairment losses		
At 1 January	**670**	614
Impairment losses for the year		56
Deletions	**(56)**	
At 31 December	**614**	670
Net book amount at 31 December	**11,868**	12,181
Net book amount at 1 January	**12,181**	12,190

Impairment review of goodwill

		$ million
Goodwill at 31 December	**2014**	2013
Upstream	**7,819**	7,812
Downstream	**3,968**	4,277
Other businesses and corporate	**81**	92
	11,868	12,181

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 Lubricants and Other.

For information on significant estimates and judgements made in relation to impairments see Impairment of property, plant and equipment, intangibles and goodwill within Note 1.

Upstream

		$ million
	2014	2013
Goodwill	**7,819**	7,812
Excess of recoverable amount over carrying amount	**26,077**	6,811

The table above shows the carrying amount of goodwill for the segment and the excess of the recoverable amount over the carrying amount (the headroom).

In 2014, the recoverable amount is calculated using a fair value less costs of disposal approach, whereas a value-in-use approach was used in 2013. The change in valuation technique was made in order to more accurately reflect the recoverable amount, based on our view of assumptions that would be used by a market participant. Both the fair value less costs of disposal and value-in-use calculations are 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 (for value in use) and reserves and risked resources (for fair value less costs of disposal). The fair value calculation is based primarily on level 3 inputs as defined by the IFRS 13 Fair value measurement hierarchy. As the production profile and related cash flows can be estimated from BP s experience, management believes that the estimated cash flows expected to be generated over the life of each field is the appropriate basis upon which to assess goodwill and individual assets for impairment. The estimated 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, 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 management. Capital expenditure, operating costs and expected hydrocarbon production profiles are derived from the business segment plan adjusted for assumptions reflecting the current price environment. 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 and resource volumes approved as part of BP s centrally controlled process for the estimation of proved and probable reserves and total resources. Intangible assets are deemed to have a recoverable amount equal to their carrying amount. Consistent with prior years, the 2014 review for impairment was carried out during the fourth quarter.

The key assumptions used in the fair value less costs of disposal calculation are oil and natural gas prices (see Note 1), production volumes and the discount rate (see Note 1). 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 15% below the current assumption for 2020 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 there is no reasonably possible change in the price assumption for natural gas that would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment.

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 847mmboe per year

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12. Goodwill and impairment review of goodwill continued

(2013 597mmboe per year). It is estimated that if production volume were to be reduced by approximately 5% 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 post-tax discount rate was approximately 10% 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

			2014			2013
	Lubricants	**Other**	**Total**	Lubricants	Other	Total
Goodwill	**3,264**	**704**	**3,968**	3,518	759	4,277

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.

Lubricants

As permitted by IAS 36, the detailed calculations of the Lubricants unit s recoverable amount performed in the most recent detailed calculation in 2013 were used for the 2014 impairment test as the criteria in that standard were considered satisfied: the headroom was substantial in 2013; there have been no significant changes in the assets and liabilities; and the likelihood that the recoverable amount would be less than the carrying amount at the time was remote.

The key assumptions to which the calculation of value in use for the Lubricants unit is most sensitive are operating unit margins, sales volumes, and discount rate. The values assigned to these key assumptions reflect past experience. No reasonably possible change in any of these key assumptions would cause the unit s carrying amount to exceed its recoverable amount. Cash flows beyond the two-year plan period were extrapolated using a nominal 3% growth rate.

13. Intangible assets

$ million

			2014			2013
	Exploration and appraisal expenditure[a]	**Other intangibles**	**Total**	Exploration and appraisal expenditure[a]	Other intangibles	Total
Cost						
At 1 January	**21,742**	**3,936**	**25,678**	24,511	3,739	28,250
Exchange adjustments		**(175)**	**(175)**		(5)	(5)
Acquisitions		**455**	**455**			

Additions	**2,871**	**394**	**3,265**	4,464	336	4,800
Transfers	**(993)**		**(993)**	(4,365)		(4,365)
Deletions	**(1,897)**	**(342)**	**(2,239)**	(2,868)	(134)	(3,002)
At 31 December	**21,723**	**4,268**	**25,991**	21,742	3,936	25,678
Amortization						
At 1 January	**877**	**2,762**	**3,639**	1,077	2,541	3,618
Exchange adjustments		**(72)**	**(72)**		(2)	(2)
Charge for the year	**3,029**	**304**	**3,333**	2,710	267	2,977
Impairment losses		**50**	**50**	253	85	338
Transfers				(365)		(365)
Deletions	**(1,527)**	**(339)**	**(1,866)**	(2,798)	(129)	(2,927)
At 31 December	**2,379**	**2,705**	**5,084**	877	2,762	3,639
Net book amount at 31 December	**19,344**	**1,563**	**20,907**	20,865	1,174	22,039
Net book amount at 1 January	**20,865**	**1,174**	**22,039**	23,434	1,198	24,632

[a] For further information see Intangible assets within Note 1 and Note 6.

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14. Investments in joint ventures

The following table provides aggregated summarized financial information relating to the group s share of joint ventures.

			$ million
	2014	2013	2012
Sales and other operating revenues	**12,208**	12,507	12,507
Profit before interest and taxation	**1,210**	1,076	778
Finance costs	**125**	130	113
Profit before taxation	**1,085**	946	665
Taxation	**515**	499	405
Profit for the year	**570**	447	260
Other comprehensive income	**(15)**	38	(52)
Total comprehensive income	**555**	485	208
Non-current assets	**11,586**	11,576	
Current assets	**2,853**	3,095	
Total assets	**14,439**	14,671	
Current liabilities	**2,222**	2,276	
Non-current liabilities	**3,774**	3,499	
Total liabilities	**5,996**	5,775	
Net assets	**8,443**	8,896	
Group investment in joint ventures			
Group share of net assets (as above)	**8,443**	8,896	
Loans made by group companies to joint ventures	**310**	303	
	8,753	9,199	

Transactions between the group and its joint ventures are summarized below.

Sales to joint ventures		**2014**		2013		$ million 2012
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	**3,148**	**300**	4,125	342	4,272	379

Purchases from joint ventures		**2014**		2013		$ million 2012
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	**907**	**129**	503	51	1,107	116

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.

15. Investments in associates

The following table provides aggregated summarized 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
	Income statement Earnings from associates after interest and tax			Balance sheet Investments in associates	
	2014	2013	2012	**2014**	2013
Rosneft	**2,101**	2,058		**7,312**	13,681
TNK-BP			2,986		
Other associates	**701**	684	689	**3,091**	2,955
	2,802	2,742	3,675	**10,403**	16,636

The associate that is material to the group at both 31 December 2014 and 2013 is Rosneft. In 2013, BP sold its 50% interest in TNK-BP to Rosneft and increased its investment in Rosneft. The net cash inflow in 2013 relating to the transaction included in Net cash used in investing activities in the cash flow statement was $11.8 billion. From 22 October 2012, the investment in TNK-BP was classified as an asset held for sale and, therefore, equity accounting ceased. Profits of approximately $738 million and $731 million were not recognized in 2013 and 2012 respectively as a result of the discontinuance of equity accounting.

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15. Investments in associates continued

Since 21 March 2013, BP has owned 19.75% of the voting shares of Rosneft. Rosneft shares are listed on the MICEX stock exchange in Moscow and its global depositary 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 2014.

BP classifies its investment in Rosneft as an associate because, in management s judgement, BP has significant influence over Rosneft; see Note 1 Interests in other entities Significant estimate or judgement: accounting for interests in other entities. The group s investment in Rosneft is a foreign operation, the functional currency of which is the Russian rouble. The reduction in the group s equity-accounted investment balance for Rosneft at 31 December 2014 compared with 31 December 2013 was principally due to the weakening of the Russian rouble compared to the US dollar, the effects of which have been recognized in other comprehensive income.

The fair value of BP s 19.75% shareholding in Rosneft was $7,346 million at 31 December 2014 (2013 $15,937 million) based on the quoted market share price of $3.51 per share (2013 $7.62 per share).

The following table provides summarized financial information relating to the group s material associates. This information is presented on a 100% basis and reflects adjustments made by BP to the associates own results in applying the equity method of accounting. BP adjusts Rosneft s results for the accounting required under IFRS relating to BP s purchase of its interest in Rosneft and the amortization of the deferred gain relating to the disposal of BP s interest in TNK-BP. The adjustments relating to Rosneft have increased the reported profit for 2014, as shown in the table below, compared with the equivalent amount in Russian roubles that we expect Rosneft to report in its own financial statements under IFRS. Consistent with other line items in the income statement, the amount reported for Rosneft sales and other operating revenue is calculated by translating the amounts reported in Russian roubles into US dollars using the average exchange rate for the year.

			$ million Gross amount
	2014 **Rosneft**	2013 Rosneft	2012 TNK-BP[a]
Sales and other operating revenues	**142,856**	122,866	49,350
Profit before interest and taxation	**19,367**	14,106	8,810
Finance costs	**5,230**	1,337	168
Profit before taxation	**14,137**	12,769	8,642
Taxation	**3,428**	2,137	1,958
Non-controlling interests	**71**	213	712
Profit for the year	**10,638**	10,419	5,972
Other comprehensive income	**(13,038)**	(441)	26
Total comprehensive income	**(2,400)**	9,978	5,998
Non-current assets	**101,073**	149,149	
Current assets	**38,278**	48,775	
Total assets	**139,351**	197,924	
Current liabilities	**36,400**	43,175	
Non-current liabilities	**65,266**	83,458	
Total liabilities	**101,666**	126,633	

Net assets	**37,685**	71,291
Less: non-controlling interests	**663**	2,020
	37,022	69,271

[a] BP ceased equity accounting for TNK-BP on 22 October 2012.

The group received dividends of $693 million from Rosneft in 2014, net of withholding tax (2013 dividends of $456 million from Rosneft and 2012 dividends of $709 million from TNK-BP).

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15. Investments in associates continued

Summarized financial information for the group s share of associates is shown below. 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
			2014			2013			2012
	Rosneft[a]	**Other**	**Total**	Rosneft	Other[b]	Total	TNK-BP	Other	Total
Sales and other operating revenues	**28,214**	**9,724**	**37,938**	24,266	12,998	37,264	24,675	11,965	36,640
Profit before interest and taxation	**3,825**	**938**	**4,763**	2,786	908	3,694	4,405	906	5,311
Finance costs	**1,033**	**7**	**1,040**	264	11	275	84	16	100
Profit before taxation	**2,792**	**931**	**3,723**	2,522	897	3,419	4,321	890	5,211
Taxation	**677**	**230**	**907**	422	213	635	979	201	1,180
Non-controlling interests	**14**		**14**	42		42	356		356
Profit for the year	**2,101**	**701**	**2,802**	2,058	684	2,742	2,986	689	3,675
Other comprehensive income	**(2,575)**	**10**	**(2,565)**	(87)	2	(85)	13	(6)	7
Total comprehensive income	**(474)**	**711**	**237**	1,971	686	2,657	2,999	683	3,682
Non-current assets	**19,962**	**2,975**	**22,937**	29,457	3,148	32,605			
Current assets	**7,560**	**2,199**	**9,759**	9,633	2,477	12,110			
Total assets	**27,522**	**5,174**	**32,696**	39,090	5,625	44,715			
Current liabilities	**7,189**	**1,614**	**8,803**	8,527	2,114	10,641			
Non-current liabilities	**12,890**	**921**	**13,811**	16,483	1,053	17,536			
Total liabilities	**20,079**	**2,535**	**22,614**	25,010	3,167	28,177			
Net assets	**7,443**	**2,639**	**10,082**	14,080	2,458	16,538			
Less: non-controlling interests	**131**		**131**	399		399			
	7,312	**2,639**	**9,951**	13,681	2,458	16,139			
Group investment in associates	**7,312**	**2,639**	**9,951**	13,681	2,458	16,139			

Group share of net assets (as above)						
Loans made by group companies to associates		**452**	**452**		497	497
	7,312	**3,091**	**10,403**	13,681	2,955	16,636

[a] On 1 October 2014, Rosneft adopted hedge accounting in relation to a portion of highly probable future export revenue denominated in US dollars. Since 1 October 2014, foreign exchange gains and losses arising on the retranslation of borrowings denominated in currencies other than the Russian rouble and designated as hedging instruments have been recognized initially in other comprehensive income, and will be reclassified to the income statement as the hedged revenue is recognized over the next five years.

[b] An amendment has been made to the amount previously disclosed for Sales and other operating revenues.

Transactions between the group and its associates are summarized below.

$ million

Sales to associates		**2014**		2013		2012
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	**9,589**	**1,258**	5,170	783	3,771	401

$ million

Purchases from associates		**2014**		2013		2012
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	**22,703**	**2,307**	21,205	3,470	9,135	932

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.

BP has commitments amounting to $6,946 million (2013 $6,077 million) in relation to contracts with its associates for the purchase of crude oil and oil products, transportation and storage.

The majority of the sales to, purchases from, and commitments in relation to contracts with associates relate to crude oil and oil products transactions with Rosneft.

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16. Other investments

				$ million
		2014		2013
	Current	**Non-current**	Current	Non-current
Equity investments[a]		**420**		291
Repurchased gas pre-paid bonds	**254**	**153**	276	408
Contingent consideration	**9**	**56**	186	292
Other	**66**	**599**	5	574
	329	**1,228**	467	1,565

[a] The majority of equity investments are unlisted.

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 both 31 December 2014 and 2013 the group had contingent consideration receivable, classified as an available-for-sale financial asset, in respect of the disposal of the Devenick field in 2013.

Other non-current investments at 31 December 2014 of $599 million relate to life insurance policies (2013 $574 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 gains of $41 million were recognized in the income statement (2013 $4 million loss and 2012 $70 million gain).

17. Inventories

		$ million
	2014	2013
Crude oil	**5,614**	10,190
Natural gas	**285**	235
Refined petroleum and petrochemical products	**8,975**	15,427
	14,874	25,852
Supplies	**3,051**	2,735
	17,925	28,587
Trading inventories	**448**	644
	18,373	29,231
Cost of inventories expensed in the income statement	**281,907**	298,351

The inventory valuation at 31 December 2014 is stated net of a provision of $2,879 million (2013 $322 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 $2,625 million (2013 $195 million charge).

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.

18. Trade and other receivables

				$ million
		2014		2013
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**19,671**	**166**	28,868	183
Amounts receivable from joint ventures and associates	**1,558**		1,213	47
Other receivables	**7,863**	**1,293**	6,594	2,725
	29,092	**1,459**	36,675	2,955
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**1,154**	**2,701**	2,457	2,442
Other receivables	**792**	**627**	699	588
	1,946	**3,328**	3,156	3,030
	31,038	**4,787**	39,831	5,985

[a] See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 27 for further information.

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19. Valuation and qualifying accounts

$ million

	2014		2013		2012	
	Accounts receivable	**Fixed asset investments**	Accounts receivable	Fixed asset investments	Accounts receivable	Fixed asset investments
At 1 January	**343**	**168**	489	349	332	643
Charged to costs and expenses	**127**	**438**	82	4	240	196
Charged to other accounts[a]	**(24)**	**(2)**	(4)	4	7	18
Deductions	**(115)**	**(87)**	(224)	(189)	(90)	(508)
At 31 December	**331**	**517**	343	168	489	349

[a] Principally exchange adjustments.

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.

For information on significant estimates and judgements made in relation to the recoverability of trade receivables see Impairment of loans and receivables within Note 1.

20. Trade and other payables

$ million

	2014		2013	
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**23,074**		28,926	
Amounts payable to joint ventures and associates	**2,436**		3,576	47
Other payables	**11,832**	**2,985**	11,288	4,235
	37,342	**2,985**	43,790	4,282
Non-financial liabilities				
Other payables	**2,776**	**602**	3,369	474
	40,118	**3,587**	47,159	4,756

Trade and other payables are predominantly interest free. See Note 27 for further information.

21. Provisions

$ million

	Decommissioning	**Environmental[a]**	**Litigation and claims**	**Clean Water Act penalties**	**Other**	**Total**
At 1 January 2014	**17,205**	**3,454**	**4,911**	**3,510**	**2,880**	**31,960**

Exchange adjustments	**(489)**	**(18)**	**(12)**		**(122)**	**(641)**
Acquisitions	**8**				**13**	**21**
New or increased provisions	**2,216**	**561**	**1,290**		**1,101**	**5,168**
Write-back of unused provisions	**(60)**	**(92)**	**(27)**		**(252)**	**(431)**
Unwinding of discount	**202**	**19**	**12**		**24**	**257**
Change in discount rate	**778**	**21**	**14**		**9**	**822**
Utilization	**(682)**	**(1,098)**	**(1,449)**		**(565)**	**(3,794)**
Deletions	**(458)**				**(6)**	**(464)**
At 31 December 2014	**18,720**	**2,847**	**4,739**	**3,510**	**3,082**	**32,898**
Of which current	**836**	**927**	**1,420**		**635**	**3,818**
non-current	**17,884**	**1,920**	**3,319**	**3,510**	**2,447**	**29,080**
Of which Gulf of Mexico oil spill[b]		**1,141**	**3,954**	**3,510**		**8,605**

[a] Spill response provisions are now included within environmental provisions as they are no longer individually significant.

[b] Further information on the financial impacts of the Gulf of Mexico oil spill is provided in Note 2.

The decommissioning provision comprises the future cost of decommissioning oil and natural gas wells, facilities and related pipelines. The environmental provision includes provisions for costs related to the control, abatement, clean-up or elimination of environmental pollution relating to soil, groundwater, surface water and sediment contamination. The litigation and claims 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 2014 are provisions for deferred employee compensation of $553 million (2013 $602 million).

For information on significant estimates and judgements made in relation to provisions, including those for the Gulf of Mexico oil spill, see Provisions, contingencies and reimbursement assets within Note 1.

22. 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 benefit 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.

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22. Pensions and other post-retirement benefits continued

For information on significant estimates and judgements made in relation to accounting for these plans see Pensions and other post-retirement benefits within Note 1.

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 corporate trustee whose board is composed of four member-nominated directors, four company-nominated directors, including an independent director and an independent chairman nominated by the company. 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. 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. Historically this has included a funded final salary pension plan for certain heritage employees and a cash balance arrangement for new joiners, but with effect from 2015 all employees who are members of the final salary pension plan accrue benefits only under a cash balance arrangement. 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 BP employees appointed by the president of BP Corporation North America Inc. (the appointing officer). 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. In the US, group companies also 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.

In the Eurozone, there are defined benefit pension plans in Germany, France, the Netherlands and other countries. In Germany and France, the majority of the pensions are unfunded, in line with market practice. In Germany, the group s largest Eurozone plan, employees receive a pension and also have a choice to supplement their core pension through salary sacrifice. For employees who joined since 2002 the core pension benefit is a career average plan with retirement benefits based on such factors as employees pensionable salary and length of service. The returns on the notional contributions made by both the company and employees are set out in German tax law. Retired German employees take their pension benefit typically in the form of an annuity. The German plan is governed by a legal agreement between BP and the works council.

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 2014 the aggregate level of contributions was $1,252 million (2013 $1,272 million and 2012 $1,275 million). The aggregate level of contributions in 2015 is expected to be approximately $1,250 million, and includes contributions in all countries that we expect to be required to make contributions by law or under contractual agreements, as well as an allowance for discretionary funding.

For the primary UK plan there is a funding agreement between the group and the trustee. On an annual basis the latest funding position is reviewed and a schedule of contributions covering the next five years is agreed. The funding agreement can be terminated unilaterally by either party with two years notice. The minimum funding requirement therefore represents seven years of future contributions, which amounted to $4,720 million at 31 December 2014. This amount is included in the group s committed cash flows relating to pensions and other post-retirement benefit plans as set out in the table of contractual obligations on page 212. There are no such minimum funding requirements after this seven-year period, and the obligation is taken into account in the determination of the amount of any pension plan surplus recognized on the balance sheet.

Contributions in the US are determined by legislation and are supplemented by discretionary contributions. All of the contributions made into the US plan in 2014 were discretionary and no statutory funding requirement is expected in the next 12 months.

There was no minimum funding requirement for the US plan, and no significant minimum funding requirements in other countries at 31 December 2014.

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 2014. 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 and a valuation as at 31 December 2014 is currently under way. A valuation of the US plan is carried out annually.

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 the accrued benefit obligation at 31 December and pension expense for the following year.

									%
Financial assumptions used to determine benefit obligation	UK			US			Eurozone		
	2014	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Discount rate for plan liabilities	**3.6**	4.6	4.4	**3.7**	4.3	3.3	**2.0**	3.6	3.5
Rate of increase in salaries	**4.5**	5.1	4.9	**4.0**	3.9	4.2	**3.4**	3.4	3.4
Rate of increase for pensions in payment	**3.0**	3.3	3.1				**1.8**	1.8	1.8
Rate of increase in deferred pensions	**3.0**	3.3	3.1				**0.7**	0.7	0.7
Inflation for plan liabilities	**3.0**	3.3	3.1	**1.6**	2.1	2.4	**2.0**	2.0	2.0

Financial assumptions used to determine benefit expense	UK			US			Eurozone		
	2014	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Discount rate for plan service cost	**4.8**	4.4	4.8	**4.6**	3.3	4.3	**3.9**	3.5	4.8
Discount rate for plan other finance expense	**4.6**	4.4	4.8	**4.3**	3.3	4.3	**3.6**	3.5	4.8
Inflation for plan service cost	**3.4**	3.1	3.2	**2.1**	2.4	1.9	**2.0**	2.0	2.0

The discount rate assumptions are based on third-party AA corporate bond indices and for our largest plans in the UK, US and the Eurozone 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. The Eurozone inflation rate assumption is based on the central bank inflation target. In other countries we use one of these approaches, or advice from the local actuary depending on the information available. 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.

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22. Pensions and other post-retirement benefits continued

The assumptions for the rate of increase in salaries are based on the inflation assumption plus an allowance for expected long-term real salary growth. These include allowance for promotion-related salary growth, of up to 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 the Eurozone where our mortality assumptions are as follows:

Years

Mortality assumptions	UK			US			Eurozone		
	2014	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Life expectancy at age 60 for a male currently aged 60	**28.3**	27.8	27.7	**25.6**	24.9	24.9	**24.7**	24.4	24.3
Life expectancy at age 60 for a male currently aged 40	**30.9**	30.7	30.6	**27.4**	26.4	26.3	**27.3**	26.9	26.9
Life expectancy at age 60 for a female currently aged 60	**29.4**	29.5	29.4	**29.1**	26.5	26.4	**28.7**	28.5	28.5
Life expectancy at age 60 for a female currently aged 40	**31.8**	32.2	32.1	**30.9**	27.3	27.3	**31.1**	30.7	30.6

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 of such assets 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 asset allocation policy for the major plans is as follows:

	UK	US
Asset category	%	%
Total equity (including private equity)	**70**	**60**
Bonds/cash	**23**	**40**
Property/real estate	**7**	

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 over time, with a view to better matching of the asset portfolio with the pension liabilities. There is a similar agreement in place in the US.

BP s principal plans in the UK and US do not currently follow a liability driven investment approach, a form of investing designed to match the movement in pension plan assets with the movement in projected benefit obligations over time.

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22. 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 139.

					$ million
	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2014					
Listed equities developed markets	**16,190**	**3,026**	**415**	**420**	**20,051**
emerging markets	**2,719**	**293**	**45**	**47**	**3,104**
Private equity	**2,983**	**1,571**	**2**	**26**	**4,582**
Government issued nominal bonds	**642**	**1,535**	**753**	**604**	**3,534**
Index-linked bonds	**892**		**9**		**901**
Corporate bonds	**4,687**	**1,726**	**541**	**340**	**7,294**
Property	**2,403**	**7**	**51**	**69**	**2,530**
Cash	**1,145**	**134**	**85**	**191**	**1,555**
Other	**112**	**63**	**72**	**38**	**285**
	31,773	**8,355**	**1,973**	**1,735**	**43,836**
At 31 December 2013					
Listed equities developed markets	17,341	3,260	414	499	21,514
emerging markets	2,290	308	32	52	2,682
Private equity	2,907	1,432	2	4	4,345
Government issued nominal bonds	549	1,259	717	541	3,066
Index-linked bonds	787		12	57	856
Corporate bonds	4,427	1,323	597	385	6,732
Property	2,200	6	57	77	2,340
Cash	855	135	120	158	1,268
Other	160	55	64	49	328
	31,516	7,778	2,015	1,822	43,131
At 31 December 2012					
Listed equities developed markets	15,659	3,622	307	537	20,125
emerging markets	1,074	341	37	52	1,504
Private equity	2,879	1,468	3	4	4,354
Government issued nominal bonds	544	904	532	510	2,490
Index-linked bonds	491		9	69	569
Corporate bonds	3,850	1,255	398	368	5,871
Property	1,783	5	54	85	1,927
Cash	1,000	87	170	151	1,408
Other	66	105	200	47	418
	27,346	7,787	1,710	1,823	38,666

a

Bonds held by the UK pension plans are all denominated in sterling. Property held by the UK pension plans is in the United Kingdom.

[b] Bonds held by the US pension plans are denominated in US dollars.

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22. Pensions and other post-retirement benefits continued

	UK	US	Eurozone	Other	$ million 2014 Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	494	356	72	87	1,009
Past service cost[b]		(33)	20	1	(12)
Settlement[c]		(66)			(66)
Operating charge relating to defined benefit plans	494	257	92	88	931
Payments to defined contribution plans	30	214	11	54	309
Total operating charge	524	471	103	142	1,240
Interest income on plan assets[a]	(1,425)	(317)	(70)	(80)	(1,892)
Interest on plan liabilities	1,378	458	255	115	2,206
Other finance expense	(47)	141	185	35	314
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	1,269	768	119	31	2,187
Change in financial assumptions underlying the present value of the plan liabilities	(3,188)	(1,004)	(1,845)	(350)	(6,387)
Change in demographic assumptions underlying the present value of the plan liabilities	42	(264)	(20)	(9)	(251)
Experience gains and losses arising on the plan liabilities	(41)	13	(86)	(25)	(139)
Remeasurements recognized in other comprehensive income	(1,918)	(487)	(1,832)	(353)	(4,590)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	30,552	11,002	7,536	2,443	51,533
Exchange adjustments	(1,993)		(1,040)	(256)	(3,289)
Operating charge relating to defined benefit plans	494	257	92	88	931
Interest cost	1,378	458	255	115	2,206
Contributions by plan participants[d]	39		4	7	50
Benefit payments (funded plans)[e]	(1,231)	(865)	(83)	(119)	(2,298)
Benefit payments (unfunded plans)[e]	(10)	(238)	(370)	(24)	(642)
Acquisitions		6			6
Disposals			(18)		(18)
Remeasurements	3,187	1,255	1,951	384	6,777
Benefit obligation at 31 December[a f]	32,416	11,875	8,327	2,638	55,256
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	31,516	7,778	2,015	1,822	43,131
Exchange adjustments	(1,958)		(257)	(161)	(2,376)
Interest income on plan assets[a g]	1,425	317	70	80	1,892
Contributions by plan participants[d]	39		4	7	50
Contributions by employers (funded plans)	713	354	110	75	1,252
Benefit payments (funded plans)[e]	(1,231)	(865)	(83)	(119)	(2,298)
Acquisitions		3			3

Disposals			(5)		(5)
Remeasurements[g]	1,269	768	119	31	2,187
Fair value of plan assets at 31 December	31,773	8,355	1,973	1,735	43,836
Surplus (deficit) at 31 December	(643)	(3,520)	(6,354)	(903)	(11,420)
Represented by					
Asset recognized	15		3	13	31
Liability recognized	(658)	(3,520)	(6,357)	(916)	(11,451)
	(643)	(3,520)	(6,354)	(903)	(11,420)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	(310)	(19)	(663)	(384)	(1,376)
Unfunded	(333)	(3,501)	(5,691)	(519)	(10,044)
	(643)	(3,520)	(6,354)	(903)	(11,420)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(32,083)	(8,374)	(2,636)	(2,119)	(45,212)
Unfunded	(333)	(3,501)	(5,691)	(519)	(10,044)
	(32,416)	(11,875)	(8,327)	(2,638)	(55,256)

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-retirement benefit plans are included in the benefit obligation.

[b] Past service costs in the US include a credit of $21 million as the result of a curtailment in the pension arrangement of a number of employees following a business reorganization and a credit of $12 million reflecting a plan amendment to a medical plan. A charge of $21 million for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes mostly in the Eurozone.

[c] Settlements represent a gain of $66 million arising from an offer to a group of plan members in the US to settle annuity liabilities with lump sum payments.

[d] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.

[e] The benefit payments amount shown above comprises $2,621 million benefits and $257 million settlements, plus $62 million of plan expenses incurred in the administration of the benefit.

[f] The benefit obligation for the US is made up of $9,033 million for pension liabilities and $2,842 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $5,220 million for pension liabilities in Germany which is largely unfunded.

[g] 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.

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22. Pensions and other post-retirement benefits continued

	UK	US	Eurozone	Other	$ million 2013 Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	497	407	81	96	1,081
Past service cost[b]	(22)	(49)	26	1	(44)
Settlement				(1)	(1)
Operating charge relating to defined benefit plans	475	358	107	96	1,036
Payments to defined contribution plans	24	223	9	44	300
Total operating charge	499	581	116	140	1,336
Interest income on plan assets[a]	(1,139)	(240)	(63)	(67)	(1,509)
Interest on plan liabilities	1,223	406	254	106	1,989
Other finance expense	84	166	191	39	480
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	2,671	730	15	99	3,515
Change in financial assumptions underlying the present value of the plan liabilities	68	1,160	62	213	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	43	(249)	2	1	(203)
Remeasurements recognized in other comprehensive income	2,782	1,655	79	248	4,764
Movements in benefit obligation during the year					
Benefit obligation at 1 January	29,323	12,874	7,364	2,720	52,281
Exchange adjustments	706		323	(192)	837
Operating charge relating to defined benefit plans	475	358	107	96	1,036
Interest cost	1,223	406	254	106	1,989
Contributions by plan participants[c]	37		4	9	50
Benefit payments (funded plans)[d]	(1,087)	(1,365)	(87)	(105)	(2,644)
Benefit payments (unfunded plans)[d]	(5)	(285)	(365)	(29)	(684)
Disposals	(9)	(61)		(13)	(83)
Remeasurements[e]	(111)	(925)	(64)	(149)	(1,249)
Benefit obligation at 31 December[a f]	30,552	11,002	7,536	2,443	51,533
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	27,346	7,787	1,710	1,823	38,666
Exchange adjustments	822		92	(129)	785
Interest income on plan assets[a]	1,139	240	63	67	1,509
Contributions by plan participants[c]	37		4	9	50
Contributions by employers (funded plans)	597	386	218	71	1,272
Benefit payments (funded plans)[d]	(1,087)	(1,365)	(87)	(105)	(2,644)

Disposals	(9)			(13)	(22)
Remeasurements[e]	2,671	730	15	99	3,515
Fair value of plan assets at 31 December	31,516	7,778	2,015	1,822	43,131
Surplus (deficit) at 31 December	964	(3,224)	(5,521)	(621)	(8,402)
Represented by					
Asset recognized	1,291	6	20	59	1,376
Liability recognized	(327)	(3,230)	(5,541)	(680)	(9,778)
	964	(3,224)	(5,521)	(621)	(8,402)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	1,285	(5)	(180)	(140)	960
Unfunded	(321)	(3,219)	(5,341)	(481)	(9,362)
	964	(3,224)	(5,521)	(621)	(8,402)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(30,231)	(7,783)	(2,195)	(1,962)	(42,171)
Unfunded	(321)	(3,219)	(5,341)	(481)	(9,362)
	(30,552)	(11,002)	(7,536)	(2,443)	(51,533)

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering 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 arrangement 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 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.

[f] The benefit obligation for the US is made up of $8,364 million for pension liabilities and $2,638 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,874 million for pension liabilities in Germany which is largely unfunded.

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22. Pensions and other post-retirement benefits continued

					$ million 2012
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	477	379	55	96	1,007
Past service cost	(1)	20	84	(2)	101
Settlement			4	(3)	1
Operating charge relating to defined benefit plans	476	399	143	91	1,109
Payments to defined contribution plans	14	223	6	38	281
Total operating charge	490	622	149	129	1,390
Interest income on plan assets[a]	(1,146)	(304)	(71)	(83)	(1,604)
Interest on plan liabilities	1,250	516	282	122	2,170
Other finance expense	104	212	211	39	566
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	1,523	718	107	66	2,414
Change in financial assumptions underlying the present value of the plan liabilities	(1,476)	(1,240)	(1,037)	(26)	(3,779)
Change in demographic assumptions underlying the present value of the plan liabilities		52	(12)	(25)	15
Experience gains and losses arising on the plan liabilities	(118)	20	(101)	(23)	(222)
Remeasurements recognized in other comprehensive income	(71)	(450)	(1,043)	(8)	(1,572)

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-retirement benefit plans are included in the benefit obligation.

At 31 December 2014, reimbursement balances due from or to other companies in respect of pensions amounted to $426 million reimbursement assets (2013 $399 million) and $16 million reimbursement liabilities (2013 $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 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 2014 for the group s plans would have had the effects shown in the table below. The effects shown for the expense in 2015 comprise the total of current service cost and net finance income or expense.

	$ million
	One percentage point

	Increase	Decrease
Discount rate[a]		
Effect on pension and other post-retirement benefit expense in 2015	**(499)**	**487**
Effect on pension and other post-retirement benefit obligation at 31 December 2014	**(8,174)**	**10,632**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2015	**543**	**(406)**
Effect on pension and other post-retirement benefit obligation at 31 December 2014	**8,264**	**(6,531)**
Salary growth		
Effect on pension and other post-retirement benefit expense in 2015	**157**	**(139)**
Effect on pension and other post-retirement benefit obligation at 31 December 2014	**1,103**	**(1,080)**

[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 increase the 2015 pension and other post-retirement benefit expense by $74 million and the pension and other post-retirement benefit obligation at 31 December 2014 by $1,582 million.

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 2024 and the weighted average duration of the defined benefit obligations at 31 December 2014 are as follows:

					$ million
Estimated future benefit payments	**UK**	**US**	**Eurozone**	**Other**	**Total**
2015	**1,192**	**899**	**439**	**136**	**2,666**
2016	**1,248**	**917**	**421**	**134**	**2,720**
2017	**1,256**	**923**	**412**	**139**	**2,730**
2018	**1,329**	**921**	**400**	**146**	**2,796**
2019	**1,377**	**916**	**389**	**151**	**2,833**
2020-2024	**7,156**	**4,343**	**1,848**	**791**	**14,138**
					years
Weighted average duration	**19.0**	**9.8**	**14.5**	**14.2**	

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23. Cash and cash equivalents

		$ million
	2014	2013
Cash at bank and in hand	**5,112**	6,907
Term bank deposits	**18,392**	12,246
Cash equivalents	**6,259**	3,367
	29,763	22,520

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 2014 includes $2,264 million (2013 $1,626 million) that is restricted. The restricted cash balances include amounts required to cover initial margin on trading exchanges and certain cash balances which are subject to exchange controls.

The group holds $3 billion (2013 $2 billion) of cash outside the UK and it is not expected that any significant tax will arise on repatriation.

24. Finance debt

						$ million
			2014			2013
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**6,831**	**45,240**	**52,071**	7,340	40,317	47,657
Net obligations under finance leases	**46**	**737**	**783**	41	494	535
	6,877	**45,977**	**52,854**	7,381	40,811	48,192

The main elements of current borrowings are the current portion of long-term borrowings that is due to be repaid in the next 12 months of $6,343 million (2013 $6,230 million) and issued commercial paper of $444 million (2013 $1,050 million). Finance debt does not include accrued interest, which is reported within other payables.

At 31 December 2014, $137 million (2013 $141 million) of finance debt was secured by the pledging of assets. The remainder of finance debt was unsecured.

The following table shows the weighted average interest rates achieved through a combination of borrowings and derivative financial instruments entered into to manage interest rate and currency exposures.

	Fixed rate debt	Floating rate debt	Total

	Weighted average interest rate %	Weighted average time for which rate is fixed Years	Amount $ million	Weighted average interest rate %	Amount $ million	Amount $ million
						2014
US dollar	**3**	**3**	**14,285**	**1**	**36,275**	**50,560**
Other currencies	**6**	**19**	**871**	**1**	**1,423**	**2,294**
			15,156		**37,698**	**52,854**
						2013
US dollar	3	4	16,405	1	29,740	46,145
Other currencies	4	11	611	2	1,436	2,047
			17,016		31,176	48,192

The floating rate debt denominated in other currencies represents euro debt not swapped to US dollars, which is naturally hedged with respect to 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 2014, whereas in the balance sheet the amount is reported within current finance debt.

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). Where quoted prices are not available, quoted prices for similar instruments in active markets are used. 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
		2014		2013
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**487**	**487**	1,110	1,110
Long-term borrowings	**51,995**	**51,584**	47,398	46,547
Net obligations under finance leases	**1,343**	**783**	654	535
Total finance debt	**53,825**	**52,854**	49,162	48,192

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25. Capital disclosures and analysis of changes in net debt

The group defines capital as total equity. We maintain our financial framework to support the pursuit of value growth for shareholders, while ensuring a secure financial base. We continue to target a gearing range of 10-20% and to maintain 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 2014, the net debt ratio was 16.7% (2013 16.2%).

		$ million
At 31 December	**2014**	2013
Gross debt	**52,854**	48,192
Less: fair value asset of hedges related to finance debt	**445**	477
	52,409	47,715
Less: cash and cash equivalents	**29,763**	22,520
Net debt	**22,646**	25,195
Equity	**112,642**	130,407
Net debt ratio	**16.7%**	16.2%

An analysis of changes in net debt is provided below.

						$ million
			2014			2013
Movement in net debt	**Finance debt[a]**	**Cash and cash equivalents**	**Net debt**	Finance debt[a]	Cash and cash equivalents	Net debt
At 1 January	**(47,715)**	**22,520**	**(25,195)**	(47,100)	19,635	(27,465)
Exchange adjustments	**1,160**	**(671)**	**489**	(219)	40	(179)
Net cash flow	**(5,419)**	**7,914**	**2,495**	(836)	2,845	2,009
Movement in finance debt relating to investing activities				632		632
Other movements	**(435)**		**(435)**	(192)		(192)
At 31 December	**(52,409)**	**29,763**	**(22,646)**	(47,715)	22,520	(25,195)

[a] Including the fair value of associated derivative financial instruments.

26. Operating leases

The minimum lease payments charged to the income statement in the year were $6,324 million (2013 $5,961 million and 2012 $5,257 million).

The future minimum lease payments at 31 December 2014, before deducting related rental income from operating sub-leases of $234 million (2013 $223 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	**2014**	2013
Payable within		
1 year	**5,401**	5,188
2 to 5 years	**9,916**	10,408
Thereafter	**3,468**	3,590
	18,785	19,186

In the case of an operating lease entered into by BP as the operator of a joint operation, the amounts included in the totals disclosed 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.

Typical durations of operating leases are up to forty years for leases of land and buildings, up to fifteen years for leases of ships and commercial vehicles and up to ten years for leases of plant and machinery.

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 2014, the future minimum lease payments relating to drilling rigs amounted to $8,180 million (2013 $8,776 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.

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27. 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 2014	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								
Other investments								
equity shares	16		420					420
other	16		538		599			1,137
Loans		992						992
Trade and other receivables	18	30,551						30,551
Derivative financial instruments	28				8,511	1,096		9,607
Cash and cash equivalents	23	23,504	2,989	3,270				29,763
Financial liabilities								
Trade and other payables	20						(40,327)	(40,327)
Derivative financial instruments	28				(6,100)	(788)		(6,888)
Accruals							(7,963)	(7,963)
Finance debt	24						(52,854)	(52,854)
		55,047	3,947	3,270	3,010	308	(101,144)	(35,562)
At 31 December 2013								
Financial assets								
Other investments								
equity shares	16		291					291
other	16		1,167		574			1,741
Loans		979						979
Trade and other receivables	18	39,630						39,630
Derivative financial instruments	28				5,189	995		6,184
Cash and cash equivalents	23	19,153	2,267	1,100				22,520
Financial liabilities								
	20						(48,072)	(48,072)

Trade and other payables								
Derivative financial instruments	28				(4,159)	(388)		(4,547)
Accruals							(9,507)	(9,507)
Finance debt	24						(48,192)	(48,192)
		59,762	3,725	1,100	1,604	607	(105,771)	(38,973)

The fair value of finance debt is shown in Note 24. 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 and interest rates; credit risk; and liquidity risk.

The group financial risk committee (GFRC) advises the group chief financial officer (CFO) who oversees the management of these risks. The GFRC is chaired by the CFO and consists of a group of senior managers including the group treasurer and the heads of the group finance, tax and the integrated supply and trading functions. The purpose of the committee is to advise on financial risks and the appropriate financial risk governance framework for the group. The committee provides assurance to the CFO and the group chief executive (GCE), and via the GCE to the board, that the group s financial risk-taking activity is governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with group policies and group risk appetite.

The group s trading activities in the oil, natural gas and power markets are managed within the integrated supply and trading function, while the activities in the financial markets are managed by the treasury function, working under the compliance and control structure of the integrated supply and trading function. All derivative activity is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control.

The integrated supply and trading function maintains formal governance processes that provide oversight of market risk, credit risk and operational 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 and interest rate risk, each of which is discussed below.

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27. Financial instruments and financial risk factors continued

(i) Commodity price risk

The group s integrated supply and trading function uses conventional financial and commodity instruments and physical cargoes and pipeline positions 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 in liquid periods 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. Trading activity occurring in liquid periods is subject to value-at-risk limits for each trading activity and for this trading activity in total. The board has delegated a limit of $100 million value at risk in support of this trading activity. Alternative measures are used to monitor exposures which are outside liquid periods and which cannot be actively risk-managed.

In addition, the group has embedded derivatives relating to certain natural gas contracts. The net fair value of these contracts was a liability of $214 million at 31 December 2014 (2013 liability of $652 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 28.

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 2014 the most significant open contracts in place were for $321 million sterling (2013 $723 million sterling).

For other UK, European and Australian operational requirements the group uses cylinders (purchased call and sold put options) to manage the estimated exposures on a 12-month rolling basis. At 31 December 2014, the open positions relating to cylinders consisted of receive sterling, pay US dollar cylinders for $2,787 million (2013 $2,770 million); receive euro, pay US dollar cylinders for $867 million (2013 $962 million); receive Australian dollar, pay US dollar cylinders for $418 million (2013 $401 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 2014, the total foreign currency net borrowings not swapped into US dollars amounted to $871 million (2013 $665 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.

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 2014 was 71% of total finance debt outstanding (2013 65%). The weighted average interest rate on finance debt at 31 December 2014 was 2% (2013 2%) and the weighted average maturity of fixed rate debt was four years (2013 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 2015, it is estimated that the group s finance costs for 2015 would increase by approximately $377 million (2013 $312 million increase).

(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 2014 were $83 million (2013 $199 million) in respect of liabilities of joint ventures and associates and $244 million (2013 $305 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 is 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.

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27. Financial instruments and financial risk factors continued

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 2014, the group had in place credit enhancements designed to mitigate approximately $10.8 billion of credit risk (2013 $13 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 2014 it is estimated that over 70% (2013 over 80%) 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 2014, 89% of the cash and cash equivalents balance was deposited with financial institutions rated at least A- by Standard & Poor s Rating Services and Fitch Ratings, and A3 by Moody s Investors Service. Of the total cash and cash equivalents at year end, $8,184 million was held in collateralised tri-partite repurchase agreements. The collateral is held by third-party custodians and would only be released to BP in the event of repayment default by the borrower.

Trade and other receivables classified as financial assets are analysed in the table below. By comparing the BP credit ratings to the equivalent external credit ratings, it is estimated that approximately 75-85% (2013 approximately 70-80%) of the unmitigated trade receivables portfolio exposure is of investment grade credit quality.

		$ million
Trade and other receivables at 31 December	**2014**	2013
Neither impaired nor past due	**28,519**	37,201
Impaired (net of provision)	**37**	27
Not impaired and past due in the following periods		
within 30 days	**841**	1,054
31 to 60 days	**249**	249
61 to 90 days	**178**	216
over 90 days	**727**	883
	30,551	39,630

Movements in the impairment provision for trade receivables are shown in Note 19.

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.

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 2014	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	Cash collateral (received) pledged	Net amount
Derivative assets	**11,515**	**(2,383)**	**9,132**	**(1,164)**	**(458)**	**7,510**
Derivative liabilities	**(8,971)**	**2,383**	**(6,588)**	**1,164**		**(5,424)**
Trade receivables	**10,502**	**(6,080)**	**4,422**	**(485)**	**(145)**	**3,792**
Trade payables	**(9,062)**	**6,080**	**(2,982)**	**485**		**(2,497)**
At 31 December 2013						
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)

(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.

Standard & Poor s Rating Services changed BP s long-term credit rating to A (negative outlook) from A (positive outlook) and Moody s Investors Service rating changed to A2 (negative outlook) from A2 (stable outlook) during 2014.

During 2014, $11.8 billion of long-term taxable bonds were issued with terms ranging from 5 to 12 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 $29.8 billion at 31 December 2014 (2013 $22.5 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2014, 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 $7,150 million with a number of banks, allowing LCs to be issued for a maximum two-year duration. There were also uncommitted secured LC facilities in place at 31 December 2014 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.

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27. Financial instruments and financial risk factors continued

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

	2014				2013			
	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	**37,342**	**7,102**	**6,877**	**892**	43,790	8,960	7,381	885
1 to 2 years	**708**	**493**	**6,311**	**776**	1,007	207	6,630	752
2 to 3 years	**757**	**119**	**5,652**	**672**	822	66	6,720	621
3 to 4 years	**1,446**	**76**	**5,226**	**578**	761	73	5,828	498
4 to 5 years	**23**	**41**	**6,056**	**479**	1,405	37	5,279	388
5 to 10 years	**24**	**95**	**19,504**	**1,111**	207	113	15,933	809
Over 10 years	**27**	**37**	**3,228**	**521**	80	51	421	119
	40,327	**7,963**	**52,854**	**5,029**	48,072	9,507	48,192	4,072

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 28. 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 settlement amounts (inflows) for the receive leg of derivatives that are settled separately from the pay leg, which amount to $14,615 million at 31 December 2014 (2013 $12,222 million) to be received on the same day as the related cash outflows.

$ million

	2014	2013
Within one year	**293**	1,095
1 to 2 years	**2,959**	293
2 to 3 years	**2,690**	2,959
3 to 4 years	**1,505**	2,577
4 to 5 years	**1,700**	1,505
5 to 10 years	**5,764**	3,835
Over 10 years	**1,325**	
	16,236	12,264

28. 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 27. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts.

For information on significant estimates and judgements made in relation to the application of hedge accounting and the valuation of derivatives see Derivative financial instruments within Note 1.

The fair values of derivative financial instruments at 31 December are set out below.

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.

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28. Derivative financial instruments continued

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.

				$ million
		2014		2013
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**122**	**(902)**	192	(111)
Oil price derivatives	**3,133**	**(1,976)**	810	(806)
Natural gas price derivatives	**3,859**	**(2,518)**	2,840	(2,029)
Power price derivatives	**922**	**(404)**	871	(560)
Other derivatives	**389**		475	
	8,425	**(5,800)**	5,188	(3,506)
Embedded derivatives				
Commodity price contracts	**86**	**(300)**	1	(653)
	86	**(300)**	1	(653)
Cash flow hedges				
Currency forwards, futures and cylinders	**1**	**(161)**	129	(30)
Cross-currency interest rate swaps		**(97)**		(69)
	1	**(258)**	129	(99)
Fair value hedges				
Currency forwards, futures and swaps	**78**	**(518)**	340	(154)
Interest rate swaps	**1,017**	**(12)**	526	(135)
	1,095	**(530)**	866	(289)
	9,607	**(6,888)**	6,184	(4,547)
Of which current	**5,165**	**(3,689)**	2,675	(2,322)
non-current	**4,442**	**(3,199)**	3,509	(2,225)

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 27.

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 **2014**
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**120**		**2**				**122**
Oil price derivatives	**2,434**	**416**	**185**	**63**	**31**	**4**	**3,133**
Natural gas price derivatives	**1,991**	**644**	**261**	**202**	**160**	**601**	**3,859**
Power price derivatives	**488**	**203**	**87**	**50**	**39**	**55**	**922**
Other derivatives	**70**	**97**	**161**	**61**			**389**
	5,103	**1,360**	**696**	**376**	**230**	**660**	**8,425**

							$ 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

At both 31 December 2014 and 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.

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28. Derivative financial instruments continued

Derivative liabilities held for trading have the following fair values and maturities.

							$ million
							2014
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**(69)**	**(180)**	**(1)**	**(1)**	**(192)**	**(459)**	**(902)**
Oil price derivatives	**(1,714)**	**(186)**	**(61)**	**(8)**	**(6)**	**(1)**	**(1,976)**
Natural gas price derivatives	**(1,310)**	**(292)**	**(144)**	**(117)**	**(99)**	**(556)**	**(2,518)**
Power price derivatives	**(217)**	**(127)**	**(39)**	**(10)**	**(4)**	**(7)**	**(404)**
	(3,310)	**(785)**	**(245)**	**(136)**	**(301)**	**(1,023)**	**(5,800)**

							$ million
							2013
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
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)

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
							2014
	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	**170**						**170**
Level 2	**6,388**	**1,353**	**354**	**130**	**71**	**20**	**8,316**
Level 3	**483**	**374**	**409**	**255**	**159**	**642**	**2,322**
	7,041	**1,727**	**763**	**385**	**230**	**662**	**10,808**

Less: netting by counterparty	**(1,938)**	**(367)**	**(67)**	**(9)**		**(2)**	**(2,383)**
	5,103	**1,360**	**696**	**376**	**230**	**660**	**8,425**
Fair value of derivative liabilities							
Level 1	**(37)**						**(37)**
Level 2	**(4,905)**	**(1,017)**	**(197)**	**(45)**	**(202)**	**(488)**	**(6,854)**
Level 3	**(306)**	**(135)**	**(115)**	**(100)**	**(99)**	**(537)**	**(1,292)**
	(5,248)	**(1,152)**	**(312)**	**(145)**	**(301)**	**(1,025)**	**(8,183)**
Less: netting by counterparty	**1,938**	**367**	**67**	**9**		**2**	**2,383**
	(3,310)	**(785)**	**(245)**	**(136)**	**(301)**	**(1,023)**	**(5,800)**
Net fair value	**1,793**	**575**	**451**	**240**	**(71)**	**(363)**	**2,625**

$ 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

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28. Derivative financial instruments continued

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 2014	**(18)**	**313**	**86**	**475**	**856**
Gains recognized in the income statement	**350**	**152**	**141**	**94**	**737**
Settlements	**(86)**	**(56)**	**(13)**	**(180)**	**(335)**
Transfers out of level 3		**(228)**			**(228)**
Net fair value of contracts at 31 December 2014	**246**	**181**	**214**	**389**	**1,030**

					$ 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

The amount recognized in the income statement for the year relating to level 3 held for trading derivatives still held at 31 December 2014 was a $456 million gain (2013 $110 million gain related to derivatives still held at 31 December 2013).

The most significant gross assets and liabilities categorized in level 3 of the fair value hierarchy are US natural gas contracts. At 31 December 2014, the gross US natural gas price instruments dependent on inputs at level 3 of the fair value hierarchy were an asset of $586 million and liability of $526 million (net fair value of $60 million), with $126 million, net, valued using level 2 inputs. 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. The significant unobservable inputs for fair value measurements categorized within level 3 of the fair value hierarchy for the year ended 31 December 2014 are presented below.

	Unobservable inputs	Range $/mmBtu	Weighted average $/mmBtu
Natural gas price contracts	Long-dated market price	3.44-6.39	4.64

If the natural gas prices after 2019 were 10% higher (lower), this would result in a decrease (increase) in derivative assets of $85 million, and decrease (increase) in derivative liabilities of $64 million, and a net decrease (increase) in profit before tax of $21 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 net gain of $6,154 million (2013 $587 million net gain and 2012 $411 million net loss). This number does not include gains and losses on realized physical derivative contracts that have been reflected gross in the income statement within sales and purchases or the change in value of transportation and storage contracts which are not recognized under IFRS, but does include the associated financially settled contracts. The net amount for actual gains and losses relating to derivative contracts and all related items therefore differs significantly from the amount disclosed above.

Embedded derivatives

The group is a party to certain natural gas contracts containing embedded derivatives. Prior to the development of an active gas trading market, UK gas contracts were priced using a basket of available price indices, primarily relating to oil products, power and inflation. After the development of an active UK gas market, certain contracts were entered into or renegotiated using pricing formulae not directly related to gas prices, for example, oil product and power prices. In these circumstances, pricing formulae have been determined to be derivatives, embedded within the overall contractual arrangements that are not clearly and closely related to the underlying commodity. The resulting fair value relating to these contracts is recognized on the balance sheet with gains or losses recognized in the income statement.

Key information on the natural gas contracts is given below.

At 31 December	**2014**	2013
Remaining contract terms	**5 months to 3 years and 9 months**	1 year and 5 months to 4 years and 9 months
Contractual/notional amount	**70 million therms**	153 million therms

28. Derivative financial instruments continued

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 historical 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 fair value gain on commodity price embedded derivatives was $430 million (2013 gain of $459 million, 2012 gain of $347 million).

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
	2014 Commodity price	2013 Commodity price
Net fair value of contracts at 1 January	**(379)**	(1,112)
Settlements	**24**	316
Gains recognized in the income statement	**219**	142
Transfers out of level 3		258
Exchange adjustments	**10**	17
Net fair value of contracts at 31 December	**(126)**	(379)

The amount recognized in the income statement for the year relating to level 3 embedded derivatives still held at 31 December 2014 was a $220 million gain (2013 $67 million gain related to derivatives still held at 31 December 2013).

Cash flow hedges

At 31 December 2014, 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 27 outlines the group s approach to foreign currency exchange risk management. 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 amounts remaining in equity at 31 December 2014 in relation to these cash flow hedges consist of deferred losses of $160 million maturing in 2015, deferred losses of $10 million maturing in 2016 and deferred gains of $3 million maturing in 2017 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. 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 2014, 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 loss on the hedging derivative instruments recognized in the income statement in 2014 was $14 million (2013 $1,240 million loss and 2012 $536 million gain) offset by a gain on the fair value of the finance debt of $8 million (2013 $1,228 million gain and 2012 $537 million loss).

The interest rate and cross-currency interest rate swaps mature within one to twelve years, and have the same maturity terms as the debt that they are hedging. They are used to convert sterling, euro, Swiss franc, Australian dollar, Canadian dollar, Norwegian Krone and Hong Kong dollar denominated fixed rate borrowings into floating rate debt. Note 27 outlines the group s approach to interest rate and foreign currency exchange risk management.

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29. Called-up share capital

The allotted, called up and fully paid share capital at 31 December was as follows:

Issued	Shares thousand	2014 $ million	Shares thousand	2013 $ million	Shares thousand	2012 $ 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	**20,426,632**	**5,108**	20,959,159	5,240	20,813,410	5,203
Issue of new shares for the scrip dividend programme	**165,644**	**41**	202,124	51	138,406	35
Issue of new shares for employee share-based payment plans[b]	**25,598**	**6**	18,203	5	7,343	2
Repurchase of ordinary share capital[c]	**(611,913)**	**(153)**	(752,854)	(188)		
At 31 December	**20,005,961**	**5,002**	20,426,632	5,108	20,959,159	5,240
		5,023		5,129		5,261

[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] Consideration received relating to the issue of new shares for employee share-based payment plans amounted to $207 million (2013 $116 million and 2012 $47 million).

[c] Purchased for a total consideration of $4,796 million, including transaction costs of $26 million (2013 $5,493 million, including transaction costs of $30 million). All shares purchased were for cancellation. The repurchased shares represented 3% 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.

In 2014, the company completed the $8-billion share repurchase programme announced on 22 March 2013 and further continuation of share buybacks was announced on 29 April 2014. During the year, the company repurchased 612 million ordinary shares at a cost of $4,770 million (2013 753 million ordinary shares at a cost of $5,463 million). 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 $nil has been accrued at 31 December 2014 (2013 $1,430 million).

Treasury shares[a]

	2014		2013		2012	
	Shares thousand	**Nominal value $ million**	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,787,939**	**447**	1,823,408	455	1,837,508	459
Shares re-issued for employee share-based payment plans	**(16,836)**	**(4)**	(35,469)	(8)	(14,100)	(4)
At 31 December	**1,771,103**	**443**	1,787,939	447	1,823,408	455

[a] Excluding shares held by ESOPs, see Note 30 for more information.

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 8.8% (2013 8.7% and 2012 8.8%) of the called-up ordinary share capital of the company.

During 2014, the movement in treasury shares represented less than 0.1% (2013 less than 0.2% and 2012 less than 0.1%) of the ordinary share capital of the company.

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30. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2014	**5,129**	**10,061**	**1,260**	**27,206**	**43,656**
Profit for the year					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)[a]					
Cash flow hedges (including recycling)					
Share of items relating to equity-accounted entities, net of tax[a]					
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	**41**	**(41)**			
Repurchases of ordinary share capital	**(153)**		**153**		
Share-based payments, net of tax[b]	**6**	**240**			**246**
Share of equity-accounted entities changes in equity, net of tax					
Transactions involving non-controlling interests					
At 31 December 2014	**5,023**	**10,260**	**1,413**	**27,206**	**43,902**

	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[b]	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[b]	2	57			59
Transactions involving non-controlling interests					
At 31 December 2012	5,261	9,974	1,072	27,206	43,513

[a] Principally affected by a weakening of the Russian rouble compared to the US dollar.

[b] Includes new share issues and movements in treasury shares where these relate to employee share-based payment plans.

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$ million

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Profit and loss account	BP shareholders equity	Non-controlling interests	Total equity
(20,971)	3,525		(695)	(695)	103,787	129,302	1,105	130,407
					3,780	3,780	223	4,003
	(6,934)	1		1		(6,933)	(32)	(6,965)
			(203)	(203)		(203)		(203)
					(2,584)	(2,584)		(2,584)
					289	289		289
					(3,256)	(3,256)		(3,256)
					4	4		4
	(6,934)	1	(203)	(202)	(1,767)	(8,903)	191	(8,712)
					(5,850)	(5,850)	(255)	(6,105)
					(3,366)	(3,366)		(3,366)
252					(313)	185		185
					73	73		73
							160	160
(20,719)	(3,409)	1	(898)	(897)	92,564	111,441	1,201	112,642

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Profit and loss account	BP shareholders equity	Non-controlling interests	Total equity
(21,054)	5,128	685	1,090	1,775	89,184	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)

83					247	473		473
					73	73		73
							76	76
(20,971)	3,525		(695)	(695)	103,787	129,302	1,105	130,407

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Profit and loss account	BP shareholders equity	Non-controlling interests	Total equity
(21,323)	4,509	389	(122)	267	84,661	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)
269					(44)	284		284
							33	33
(21,054)	5,128	685	1,090	1,775	89,184	118,546	1,206	119,752

30. 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.

Treasury shares

Treasury shares represent BP shares repurchased and available for specific and limited purposes.

For accounting purposes shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans are treated in the same manner as treasury shares and are therefore included in the financial statements as treasury shares. The ESOPs are funded by the group and have waived their rights to dividends in respect of such shares held for future awards. Until such time as the 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 2014, the ESOPs held 34,169,554 shares (2013 32,748,354 shares and 2012 22,428,179 shares) for potential future awards, which had a market value of $219 million (2013 $253 million and 2012 $154 million). At 31 December 2014, a further 6,024,978 ordinary share equivalents (2013 12,856,914 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.

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 Derivative financial instruments and hedging activities.

Profit and loss account

The balance held on this reserve is the accumulated retained profits of the group.

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30. 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
			2014
	Pre-tax	**Tax**	**Net of tax**
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	**(6,787)**	**(178)**	**(6,965)**
Cash flow hedges (including recycling)	**(239)**	**36**	**(203)**
Share of items relating to equity-accounted entities, net of tax	**(2,584)**		**(2,584)**
Other		**289**	**289**
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	**(4,590)**	**1,334**	**(3,256)**
Share of items relating to equity-accounted entities, net of tax	**4**		**4**
Other comprehensive income	**(14,196)**	**1,481**	**(12,715)**

			$ 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

31. 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 2014 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 27.

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.

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31. Contingent liabilities continued

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.

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 it is possible that, in certain circumstances, BP could be partially or wholly responsible for decommissioning. Furthermore, as described in Provisions, contingencies and reimbursement assets within Note 1, decommissioning provisions associated with downstream and petrochemical facilities are not generally recognized as the potential obligations cannot be measured given their indeterminate settlement dates.

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.

32. Remuneration of senior management and non-executive directors

Remuneration of directors

			$ million
	2014	2013	2012
Total for all directors			
Emoluments	**14**	16	12
Amounts awarded under incentive schemes	**14**	2	3
Total	**28**	18	15

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus cash bonuses awarded for the year. There was no compensation for loss of office in 2014 (2013 $nil and 2012 $nil).

Pension contributions

During 2014 two executive directors participated in a non-contributory pension scheme established for UK employees by a separate trust fund to which contributions are made by BP based on actuarial advice. One US executive director participated in the US BP Retirement Accumulation Plan during 2014.

Further information

Full details of individual directors remuneration are given in the Directors remuneration report on page 72.

Remuneration of senior management and non-executive directors

			$ million
	2014	2013	2012
Total for senior management and non-executive directors			
Short-term employee benefits	**34**	36	29
Pensions and other post-retirement benefits	**3**	3	3
Share-based payments	**34**	43	37
Total	**71**	82	69

Senior management, comprises members of the executive team, see pages 56-57 for further information.

Short-term employee benefits

These amounts comprise fees and benefits paid to the non-executive chairman and non-executive directors, as well as salary, benefits and cash bonuses for senior management. 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 $1.5 million (2013 $3 million and 2012 $nil).

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 .

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33. Employee costs and numbers

			$ million
Employee costs	**2014**	2013	2012
Wages and salaries[a]	**10,710**	10,161	9,910
Social security costs	**983**	958	908
Share-based payments[b]	**689**	719	674
Pension and other post-retirement benefit costs	**1,554**	1,816	1,956
	13,936	13,654	13,448

	2014			2013			2012		
Average number of employees[c]	**US**	**Non-US**	**Total**	US	Non-US	Total	US	Non-US	Total
Upstream	**9,100**	**15,600**	**24,700**	9,400	15,100	24,500	9,300	14,100	23,400
Downstream[d]	**8,200**	**39,900**	**48,100**	9,300	39,800	49,100	12,000	39,900	51,900
Other businesses and corporate[e f]	**1,800**	**10,100**	**11,900**	2,000	9,000	11,000	2,000	8,700	10,700
	19,100	**65,600**	**84,700**	20,700	63,900	84,600	23,300	62,700	86,000

[a] Includes termination payments of $527 million (2013 $212 million and 2012 $77 million).

[b] 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.

[c] Reported to the nearest 100.

[d] Includes 14,200 (2013 14,100 and 2012 14,700) service station staff.

[e] Includes 5,100 (2013 4,300 and 2012 3,600) agricultural, operational and seasonal workers in Brazil.

f Includes employees of the Gulf Coast Restoration Organization.

34. Auditor s remuneration

			$ million
Fees Ernst & Young	**2014**	2013	2012
The audit of the company annual accounts[a]	**27**	26	26
The audit of accounts of any subsidiaries of the company	**13**	13	13
Total audit	**40**	39	39
Audit-related assurance services[b]	**7**	8	7
Total audit and audit-related assurance services	**47**	47	46
Taxation compliance services	**1**	1	2
Taxation advisory services	**1**	1	2
Services relating to corporate finance transactions	**1**	2	2
Other assurance services	**2**	1	1
Total non-audit or non-audit-related assurance services	**5**	5	7
Services relating to BP pension plans[c]	**1**	1	1

	53	53	54

[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 $398,000 (2013 $240,000 and 2012 $50,000).
2014 includes $2 million of additional fees for 2013, and 2013 includes $3 million of additional fees for 2012.
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 (2013 $53 million and 2012 $54 million) is required to be presented as follows: audit $40 million (2013 $39 million and 2012 $39 million); other audit-related services $7 million (2013 $8 million and 2012 $7 million); tax $2 million (2013 $2 million and 2012 $4 million); and all other fees $4 million (2013 $4 million and 2012 $4 million).

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35. Subsidiaries, joint arrangements and associates

The more important subsidiaries and associates of the group at 31 December 2014 and the group percentage of ordinary share capital (to nearest whole number) are set out below. There are no individually significant joint arrangements. Those held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of investments in subsidiaries, 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
Germany			
BP Europa SE	100	Germany	Refining and marketing
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
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	
BP America Production Company	100	US	
			Exploration and production, refining and marketing pipelines and petrochemicals

BP Company North America	100	US	
BP Corporation North America	100	US	
BP Exploration & Production	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
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

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36. 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					**2014**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Sales and other operating revenues	**6,227**		**353,529**	**(6,188)**	**353,568**
Earnings from joint ventures after interest and tax			**570**		**570**
Earnings from associates after interest and tax			**2,802**		**2,802**
Equity-accounted income of subsidiaries after interest and tax		**4,531**		**(4,531)**	
Interest and other income	**2**	**193**	**910**	**(262)**	**843**
Gains on sale of businesses and fixed assets	**19**		**876**		**895**
Total revenues and other income	**6,248**	**4,724**	**358,687**	**(10,981)**	**358,678**
Purchases	**2,375**		**285,720**	**(6,188)**	**281,907**
Production and manufacturing expenses	**1,779**		**25,596**		**27,375**
Production and similar taxes	**554**		**2,404**		**2,958**
Depreciation, depletion and amortization	**545**		**14,618**		**15,163**
Impairment and losses on sale of businesses and fixed assets	**153**		**8,812**		**8,965**
Exploration expense			**3,632**		**3,632**
Distribution and administration expenses	**48**	**929**	**11,794**	**(75)**	**12,696**
Fair value gain on embedded derivatives			**(430)**		**(430)**
Profit before interest and taxation	**794**	**3,795**	**6,541**	**(4,718)**	**6,412**

Finance costs	**57**	**23**	**1,255**	**(187)**	**1,148**
Net finance (income) expense relating to pensions and other post-retirement benefits		**(50)**	**364**		**314**
Profit before taxation	**737**	**3,822**	**4,922**	**(4,531)**	**4,950**
Taxation	**279**	**42**	**626**		**947**
Profit for the year	**458**	**3,780**	**4,296**	**(4,531)**	**4,003**
Attributable to					
BP shareholders	**458**	**3,780**	**4,073**	**(4,531)**	**3,780**
Non-controlling interests			**223**		**223**
	458	**3,780**	**4,296**	**(4,531)**	**4,003**

Statement of comprehensive income

					$ million
For the year ended 31 December					**2014**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Profit for the year	**458**	**3,780**	**4,296**	**(4,531)**	**4,003**
Other comprehensive income		**(1,840)**	**(10,875)**		**(12,715)**
Equity-accounted other comprehensive income of subsidiaries		**(10,843)**		**10,843**	
Total comprehensive income	**458**	**(8,903)**	**(6,579)**	**6,312**	**(8,712)**
Attributable to					
BP shareholders	**458**	**(8,903)**	**(6,770)**	**6,312**	**(8,903)**
Non-controlling interests			**191**		**191**
	458	**(8,903)**	**(6,579)**	**6,312**	**(8,712)**

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36. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

					$ 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 continued

	$ 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
Profit for the year	840	23,451	24,160	(24,693)	23,758
Other comprehensive income		2,819	(3,711)		(892)
Equity-accounted other comprehensive income of subsidiaries		(3,696)		3,696	
Total comprehensive income	840	22,574	20,449	(20,997)	22,866
Attributable to					
BP shareholders	840	22,574	20,157	(20,997)	22,574
Non-controlling interests			292		292
	840	22,574	20,449	(20,997)	22,866

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36. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

					$ 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
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 BP Exploration (Alaska) Inc.	Guarantor 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
Equity-accounted other comprehensive income of subsidiaries		1,203		(1,203)	
Total comprehensive income	3,708	11,988	13,903	(17,373)	12,226
Attributable to					
BP shareholders	3,708	11,988	13,665	(17,373)	11,988
Non-controlling interests			238		238
	3,708	11,988	13,903	(17,373)	12,226

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36. Condensed consolidating information on certain US subsidiaries continued

Balance sheet

$ million

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	2014 BP group
Non-current assets					
Property, plant and equipment	7,787		122,905		130,692
Goodwill			11,868		11,868
Intangible assets	473		20,434		20,907
Investments in joint ventures			8,753		8,753
Investments in associates		2	10,401		10,403
Other investments			1,228		1,228
Subsidiaries equity-accounted basis		138,863		(138,863)	
Fixed assets	8,260	138,865	175,589	(138,863)	183,851
Loans	7		5,238	(4,586)	659
Trade and other receivables			4,787		4,787
Derivative financial instruments			4,442		4,442
Prepayments	10		954		964
Deferred tax assets			2,309		2,309
Defined benefit pension plan surpluses		15	16		31
	8,277	138,880	193,335	(143,449)	197,043
Current assets					
Loans			333		333
Inventories	338		18,035		18,373
Trade and other receivables	10,323	7,159	33,463	(19,907)	31,038
Derivative financial instruments			5,165		5,165
Prepayments	31		1,393		1,424
Current tax receivable			837		837
Other investments			329		329
Cash and cash equivalents		31	29,732		29,763
	10,692	7,190	89,287	(19,907)	87,262
Total assets	18,969	146,070	282,622	(163,356)	284,305
Current liabilities					
Trade and other payables	905	2,476	56,644	(19,907)	40,118
Derivative financial instruments			3,689		3,689
Accruals	134	391	6,577		7,102
Finance debt			6,877		6,877
Current tax payable	328		1,683		2,011
Provisions	1		3,817		3,818
	1,368	2,867	79,287	(19,907)	63,615
Non-current liabilities					

Other payables	**16**	**4,563**	**3,594**	**(4,586)**	**3,587**
Derivative financial instruments			**3,199**		**3,199**
Accruals		**90**	**771**		**861**
Finance debt			**45,977**		**45,977**
Deferred tax liabilities	**1,232**		**12,661**		**13,893**
Provisions	**1,975**		**27,105**		**29,080**
Defined benefit pension plan and other post-retirement benefit plan deficits		**599**	**10,852**		**11,451**
	3,223	**5,252**	**104,159**	**(4,586)**	**108,048**
Total liabilities	**4,591**	**8,119**	**183,446**	**(24,493)**	**171,663**
Net assets	**14,378**	**137,951**	**99,176**	**(138,863)**	**112,642**
Equity					
BP shareholders equity	**14,378**	**137,951**	**97,975**	**(138,863)**	**111,441**
Non-controlling interests			**1,201**		**1,201**
	14,378	**137,951**	**99,176**	**(138,863)**	**112,642**

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36. Condensed consolidating information on certain US subsidiaries continued

Balance sheet continued

$ million

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	2013 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

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36. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

For the year ended 31 December	**Issuer BP Exploration (Alaska) Inc.**	**Guarantor BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**$ million 2014 BP group**
Net cash provided by operating activities	**92**	**15,550**	**19,241**	**(2,129)**	**32,754**
Net cash used in investing activities	**(92)**	**(5,085)**	**(14,397)**		**(19,574)**
Net cash used in financing activities		**(10,440)**	**3,045**	**2,129**	**(5,266)**
Currency translation differences relating to cash and cash equivalents			**(671)**		**(671)**
Increase in cash and cash equivalents		**25**	**7,218**		**7,243**
Cash and cash equivalents at beginning of year		**6**	**22,514**		**22,520**
Cash and cash equivalents at end of year		**31**	**29,732**		**29,763**

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2013 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

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2012 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

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Supplementary information on oil and natural gas (unaudited)[a]

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 pages 219 224.

[a] 2013 equity-accounted entities information includes BP s share of TNK-BP from 1 January to 20 March, and Rosneft for the period 21 March to 31 December.

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Oil and natural gas exploration and production activities

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2014 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	**31,496**	**10,578**	**76,476**	**3,205**	**9,796**	**39,020**		**24,177**	**5,061**	**199,809**
Unproved properties	**395**	**165**	**6,294**	**2,454**	**2,984**	**5,769**		**2,773**	**888**	**21,722**
	31,891	**10,743**	**82,770**	**5,659**	**12,780**	**44,789**		**26,950**	**5,949**	**221,531**
Accumulated depreciation	**21,068**	**6,610**	**39,383**	**190**	**5,482**	**25,105**		**13,501**	**2,215**	**113,554**
Net capitalized costs	**10,823**	**4,133**	**43,387**	**5,469**	**7,298**	**19,684**		**13,449**	**3,734**	**107,977**
Costs incurred for the year ended 31 December[b]										
Acquisition of properties										
Proved	**42**		**6**					**557**		**605**
Unproved			**346**		**75**	**57**				**478**
	42		**352**		**75**	**57**		**557**		**1,083**
Exploration and appraisal costs[c]	**279**	**16**	**888**	**109**	**325**	**899**		**194**	**201**	**2,911**
Development	**2,067**	**293**	**4,792**	**706**	**983**	**2,881**		**3,205**	**169**	**15,096**
Total costs	**2,388**	**309**	**6,032**	**815**	**1,383**	**3,837**		**3,956**	**370**	**19,090**
Results of operations for the year ended 31 December										
Sales and other operating revenues[d]										

Third parties	**529**	**77**	**1,218**	**4**	**2,802**	**2,536**		**1,135**	**1,891**	**10,192**
Sales between businesses	**1,069**	**1,662**	**14,894**	**15**	**450**	**6,289**		**6,951**	**631**	**31,961**
	1,598	**1,739**	**16,112**	**19**	**3,252**	**8,825**		**8,086**	**2,522**	**42,153**
Exploration expenditure	**94**	**47**	**1,294**	**63**	**502**	**860**		**712**	**60**	**3,632**
Production costs	**979**	**436**	**3,492**	**34**	**783**	**1,542**		**1,289**	**232**	**8,787**
Production taxes	**(234)**		**690**		**175**			**2,234**	**93**	**2,958**
Other costs (income)[e]	**(1,515)**	**77**	**3,260**	**55**	**284**	**120**	**57**	**(69)**	**306**	**2,575**
Depreciation, depletion and amortization	**506**	**676**	**3,805**	**4**	**678**	**3,343**		**2,461**	**255**	**11,728**
Impairments and (gains) losses on sale of businesses and fixed assets	**2,537**	**2,278**	**(28)**		**11**	**1,128**		**391**		**6,317**
	2,367	**3,514**	**12,513**	**156**	**2,433**	**6,993**	**57**	**7,018**	**946**	**35,997**
Profit (loss) before taxation[f]	**(769)**	**(1,775)**	**3,599**	**(137)**	**819**	**1,832**	**(57)**	**1,068**	**1,576**	**6,156**
Allocable taxes	**(1,383)**	**(1,108)**	**1,269**	**15**	**865**	**1,216**	**3**	**67**	**599**	**1,543**
Results of operations	**614**	**(667)**	**2,330**	**(152)**	**(46)**	**616**	**(60)**	**1,001**	**977**	**4,613**

Upstream and Rosneft segments replacement cost profit before interest and tax

Exploration and production activities subsidiaries (as above)	**(769)**	**(1,775)**	**3,599**	**(137)**	**819**	**1,832**	**(57)**	**1,068**	**1,576**	**6,156**
Midstream activities subsidiaries[g]	**163**	**99**	**703**	**130**	**175**	**(170)**	**(26)**	**(63)**	**653**	**1,664**
Equity-accounted entities[h]		**62**	**23**		**480**	**(33)**	**2,125**	**557**		**3,214**
Total replacement cost profit before interest and tax	**(606)**	**(1,614)**	**4,325**	**(7)**	**1,474**	**1,629**	**2,042**	**1,562**	**2,229**	**11,034**

[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 $430 million. The UK region includes a $1,016 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 $207 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.

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Oil and natural gas exploration and production activities continued

$ million

										2014
	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					**8,719**		**12,971**	**3,073**		**24,763**
Unproved properties					**5**		**376**	**25**		**406**
					8,724		**13,347**	**3,098**		**25,169**
Accumulated depreciation					**3,652**		**2,031**	**2,986**		**8,669**
Net capitalized costs					**5,072**		**11,316**	**112**		**16,500**
Costs incurred for the year ended 31 December[d]										
Acquisition of properties[c]										
Proved							**(46)**			**(46)**
Unproved							**87**			**87**
							41			**41**
Exploration and appraisal costs[d]					**5**		**128**	**4**		**137**
Development					**1,026**		**1,913**	**669**		**3,608**
Total costs					**1,031**		**2,082**	**673**		**3,786**
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties					**2,472**			**1,257**		**3,729**
Sales between businesses							**10,972**	**19**		**10,991**
					2,472		**10,972**	**1,276**		**14,720**
Exploration expenditure					**4**		**62**	**1**		**67**
Production costs					**567**		**1,318**	**152**		**2,037**
Production taxes					**721**		**5,214**	**692**		**6,627**
Other costs (income)					**4**		**302**			**306**
Depreciation, depletion and amortization					**370**		**1,509**	**371**		**2,250**

Impairments and losses on sale of businesses and fixed assets			**25**				**25**
			1,691		**8,405**	**1,216**	**11,312**
Profit (loss) before taxation			**781**		**2,567**	**60**	**3,408**
Allocable taxes			**402**		**637**	**29**	**1,068**
Results of operations			**379**		**1,930**	**31**	**2,340**
Exploration and production activities equity-accounted entities after tax (as above)			**379**		**1,930**	**31**	**2,340**
Midstream and other activities after tax[f]	**62**	**23**	**101**	**(33)**	**195**	**526**	**874**
Total replacement cost profit after interest and tax	**62**	**23**	**480**	**(33)**	**2,125**	**557**	**3,214**

[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 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] 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 interests and excludes inventory holding gains and losses.

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Oil and natural gas exploration and production activities continued

$ million

	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	2013 Total
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	4,681	187,104
Unproved properties	316	195	6,816	2,408	3,366	5,079		2,756	805	21,741
	29,630	10,235	82,129	4,909	12,175	40,799		23,482	5,486	208,845
Accumulated depreciation	18,707	3,650	38,236	193	5,063	20,082		10,069	1,962	97,962
Net capitalized costs	10,923	6,585	43,893	4,716	7,112	20,717		13,413	3,524	110,883
Costs incurred for the year ended 31 December[b]										
Acquisition of properties										
Proved			1		7					8
Unproved			158		284	30		7		479
			159		291	30		7		487
Exploration and appraisal costs[c]	178	14	1,291	194	951	883		1,090	210	4,811
Development	1,942	455	4,877	569	683	2,755		2,082	189	13,552
Total costs	2,120	469	6,327	763	1,925	3,668		3,179	399	18,850
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	1,784	10,648
	1,661	1,280	14,047	12	1,154	6,518		11,432	941	37,045

Sales between businesses	2,790	1,463	14,981	17	3,567	9,713		12,437	2,725	47,693
Exploration expenditure	280	17	437	28	1,477	387		768	47	3,441
Production costs	1,102	430	3,691	42	892	1,623		1,091	187	9,058
Production taxes	(35)		1,112		184			5,660	126	7,047
Other costs (income)[e]	(1,731)	86	3,241	55	322	89	65	84	351	2,562
Depreciation, depletion and amortization	504	490	3,268		559	3,132		2,174	207	10,334
Impairments and (gains) losses on sale of businesses and fixed assets	118	15	(80)		129	29		(16)	230	425
	238	1,038	11,669	125	3,563	5,260	65	9,761	1,148	32,867
Profit (loss) before taxation[f]	2,552	425	3,312	(108)	4	4,453	(65)	2,676	1,577	14,826
Allocable taxes	554	475	1,204	(26)	642	1,925	(2)	682	641	6,095
Results of operations	1,998	(50)	2,108	(82)	(638)	2,528	(63)	1,994	936	8,731

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	1,577	14,826
Midstream activities subsidiaries[g]	244	(40)	296	(14)	153	(154)	(4)	(29)	347	799
TNK-BP gain on sale							12,500			12,500
Equity-accounted entities[h]		28	17		405	24	2,158	553		3,185
Total replacement cost profit before interest and tax	2,796	413	3,625	(122)	562	4,323	14,589	3,200	1,924	31,310

[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.

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Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	Total
2013	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 interests and excludes inventory holding gains and losses.

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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	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b c]										
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[d e]										
Proved			256		51					307
Unproved			1,111		27	239		(68)		1,309
			1,367		78	239		(68)		1,616
Exploration and appraisal costs[f]	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[g]										
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)[h]	(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[i]	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 and TNK-BP segments 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[j]	(250)	(114)	(173)	774	163	(46)	11	32	370	767
Equity-accounted entities[k]		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] Excludes balances associated with assets held for sale.

[d] Includes costs capitalized as a result of asset exchanges.

[e] Excludes goodwill associated with business combinations.

[f] 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.

[g] Presented net of transportation costs, purchases and sales taxes.

[h] 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.

[i] 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.

[j] Midstream and other activities exclude inventory holding gains and losses.

[k] The profits of equity-accounted entities are included after interest and tax and the results exclude balances associated with assets held for sale.

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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[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)
Depreciation, depletion and amortization					328		786	538		1,652
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. Capitalised 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 interests and the net results of equity-accounted entities and excludes inventory holding gains and losses.

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Movements in estimated net proved reserves

million barrels

Crude oil[a b]	Europe		North America		South America	Africa	Asia		Australasia	2014 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	160	147	1,007		15	316		320	49	2,013
Undeveloped	374	53	752		17	180		202	19	1,597
	534	200	1,760		31	495		522	69	3,610
Changes attributable to										
Revisions of previous estimates	(41)	(68)	87		9	20		96	(2)	101
Improved recovery	2		16		1	3				23
Purchases of reserves-in-place	5							12		17
Discoveries and extensions	5				1			8		13
Production[d]	(17)	(15)	(123)		(5)	(81)		(57)	(7)	(305)
Sales of reserves-in-place			(45)		(5)					(50)
	(46)	(82)	(66)		1	(58)		59	(9)	(201)
At 31 December[e]										
Developed	159	95	1,030		10	317		384	40	2,035
Undeveloped	329	22	664		22	120		197	19	1,375
	488	117	1,694		32	437		581	59	3,409
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed					316	2	2,970	120		3,407
Undeveloped				1	314	2	1,858	7		2,182
				1	630	4	4,828	127		5,590
Changes attributable to										
Revisions of previous estimates					4	(2)	213	9		224
Improved recovery					12					12
Purchases of reserves-in-place										
Discoveries and extensions					10		187			197
Production					(26)		(297)	(36)		(359)

Sales of reserves-in-place										
						(2)	103	(27)		74
At 31 December[g]										
Developed					316	2	2,997	89		3,405
Undeveloped					314		1,933	11		2,258
				1	630	2	4,930	101		5,663
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	160	147	1,007		331	317	2,970	440	49	5,421
Undeveloped	374	53	752	1	331	182	1,858	209	19	3,779
	534	200	1,760	1	661	499	4,828	649	69	9,200
At 31 December										
Developed	159	95	1,030		326	319	2,997	473	40	5,440
Undeveloped	329	22	664		336	120	1,933	208	19	3,632
	488	117	1,694	1	662	439	4,930	682	59	9,072

[a] Crude oil includes 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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 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.

[d] Includes 10 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 38 million barrels of crude oil in respect of the 0.15% non-controlling interest in Rosneft.

[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 4,961 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 30 million barrels in Venezuela and 4,930 million barrels in Russia.

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Movements in estimated net proved reserves continued

million barrels

Natural gas liquids[a b]	Europe		North America		South America	Africa	Asia		Australasia	2014 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	9	16	290		14	4			8	342
Undeveloped	6	2	155		28	15			3	209
	15	18	444		43	20			10	551
Changes attributable to										
Revisions of previous estimates	(6)	(2)	15			(6)				1
Improved recovery			13							13
Purchases of reserves-in-place										1
Discoveries and extensions										
Production[c]	(1)	(2)	(27)		(4)	(2)			(1)	(36)
Sales of reserves-in-place			(18)							(18)
	(6)	(4)	(17)		(4)	(8)			(1)	(40)
At 31 December[d]										
Developed	6	13	323		11	5			6	364
Undeveloped	3	1	104		28	7			3	146
	9	14	427		39	12			10	510
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed						8	94			103
Undeveloped						8	21			29
						16	115			131
Changes attributable to										
Revisions of previous estimates							(69)			(69)
Improved recovery										
Purchases of reserves-in-place										
Discoveries and extensions										
Production										
Sales of reserves-in-place										
						(1)	(69)			(69)
At 31 December[f]										
Developed						15	30			46

Undeveloped						**16**		**16**
					15	**46**		**62**
Total subsidiaries and equity-accounted entities (BP share)								
At 1 January								
Developed	**9**	**16**	**290**	**14**	**13**	**94**	**8**	**444**
Undeveloped	**6**	**2**	**155**	**28**	**23**	**21**	**3**	**238**
	15	**18**	**444**	**43**	**36**	**115**	**10**	**682**
At 31 December								
Developed	**6**	**13**	**323**	**11**	**20**	**30**	**6**	**410**
Undeveloped	**3**	**1**	**104**	**28**	**7**	**16**	**3**	**163**
	9	**14**	**427**	**39**	**27**	**46**	**10**	**572**

[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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.

[d] Includes 12 million barrels of NGL 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] Total proved NGL reserves held as part of our equity interest in Rosneft is 47 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 46 million barrels in Russia.

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Movements in estimated net proved reserves continued

		million barrels
Bitumen[a b]		2014
	Rest of North America	Total
Subsidiaries		
At 1 January		
Developed		
Undeveloped	188	188
	188	188
Changes attributable to		
Revisions of previous estimates	(16)	(16)
Improved recovery		
Purchases of reserves-in-place		
Discoveries and extensions		
Production		
Sales of reserves-in-place		
	(16)	(16)
At 31 December		
Developed	9	9
Undeveloped	163	163
	172	172

[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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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Movements in estimated net proved reserves continued

million barrels

Total liquids[a b]	Europe UK	Europe Rest of Europe	North America US[c]	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2014 Total
Subsidiaries										
At 1 January										
Developed	169	163	1,297		29	320		320	57	2,354
Undeveloped	380	55	907	188	46	195		202	22	1,994
	549	217	2,204	188	74	515		523	78	4,348
Changes attributable to										
Revisions of previous estimates	(47)	(70)	101	(16)	9	14		96	(2)	86
Improved recovery	2		28		1	3				36
Purchases of reserves-in-place	5							12		18
Discoveries and extensions	5				1			8		14
Production[d]	(17)	(17)	(150)		(9)	(83)		(57)	(8)	(341)
Sales of reserves-in-place			(63)		(5)					(68)
	(52)	(86)	(83)	(16)	(3)	(66)		59	(10)	(257)
At 31 December[e]										
Developed	166	108	1,352	9	21	322		384	46	2,407
Undeveloped	332	23	769	163	50	127		197	22	1,684
	497	131	2,121	172	71	449		581	68	4,092
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed					316	10	3,063	120		3,510
Undeveloped				1	314	10	1,879	7		2,210
				1	630	20	4,943	127		5,721
Changes attributable to										
Revisions of previous estimates					4	(3)	144	9		155
Improved recovery					12					12
Purchases of reserves-in-place										
Discoveries and extensions					10		187			197
Production					(26)		(297)	(36)		(359)
Sales of reserves-in-place										

						(3)	**34**	**(27)**		**4**
At 31 December[g h]										
Developed					**316**	**17**	**3,028**	**89**		**3,451**
Undeveloped					**314**		**1,949**	**11**		**2,274**
				1	**630**	**17**	**4,976**	**101**		**5,725**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	**169**	**163**	**1,297**		**345**	**331**	**3,063**	**440**	**57**	**5,865**
Undeveloped	**380**	**55**	**907**	**188**	**359**	**205**	**1,879**	**209**	**22**	**4,204**
	549	**217**	**2,204**	**189**	**704**	**535**	**4,943**	**650**	**78**	**10,069**
At 31 December										
Developed	**166**	**108**	**1,352**	**9**	**337**	**339**	**3,028**	**473**	**46**	**5,858**
Undeveloped	**332**	**23**	**769**	**164**	**364**	**127**	**1,949**	**208**	**22**	**3,958**
	497	**131**	**2,121**	**173**	**701**	**466**	**4,976**	**682**	**68**	**9,817**

[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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 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 less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.

[e] Also includes 21 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[g] Includes 38 million barrels in respect of the non-controlling interest in Rosneft.

[h] Total proved liquid reserves held as part of our equity interest in Rosneft is 5,007 million barrels, comprising 1 million barrels in Canada, 30 million barrels in Venezuela, less than 1 million barrels in Vietnam and 4,976 million barrels in Russia.

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Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a b]	Europe		North America		South America	Africa	Asia		Australasia	2014 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	643	364	7,122	10	3,109	961		1,519	3,932	17,660
Undeveloped	314	39	2,825		6,116	1,807		3,671	1,755	16,527
	957	403	9,947	10	9,225	2,768		5,190	5,687	34,187
Changes attributable to										
Revisions of previous estimates	(260)	(46)	(29)	11	(258)	(84)		(34)	(351)	(1,050)
Improved recovery	7		582		220	28				838
Purchases of reserves-in-place	1		5					322		328
Discoveries and extensions	94		2		271	4		267		637
Production[c]	(30)	(40)	(625)	(4)	(792)	(218)		(165)	(302)	(2,177)
Sales of reserves-in-place			(266)							(266)
	(189)	(85)	(332)	7	(559)	(271)		389	(652)	(1,691)
At 31 December[d]										
Developed	382	300	7,168	17	2,352	901		1,688	3,316	16,124
Undeveloped	386	19	2,447		6,313	1,597		3,892	1,719	16,372
	768	318	9,615	17	8,666	2,497		5,580	5,035	32,496
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed					1,364	230	4,171	72		5,837
Undeveloped				1	747	135	5,054	14		5,951
				1	2,111	365	9,225	86		11,788
Changes attributable to										
Revisions of previous estimates				1	(87)	38	767	1		720
Improved recovery					23					23
Purchases of reserves-in-place					69		183			252

Discoveries and extensions										
Production[c]					**(172)**	**(3)**	**(390)**	**(18)**		**(583)**
Sales of reserves-in-place										
					(166)	**35**	**560**	**(17)**		**412**
At 31 December[f g]										
Developed				**1**	**1,228**	**400**	**4,674**	**60**		**6,363**
Undeveloped				**1**	**717**		**5,111**	**9**		**5,837**
				1	**1,945**	**400**	**9,785**	**69**		**12,200**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	**643**	**364**	**7,122**	**10**	**4,473**	**1,191**	**4,171**	**1,591**	**3,932**	**23,497**
Undeveloped	**314**	**39**	**2,825**	**1**	**6,863**	**1,942**	**5,054**	**3,685**	**1,755**	**22,478**
	957	**403**	**9,947**	**11**	**11,336**	**3,133**	**9,225**	**5,276**	**5,687**	**45,975**
At 31 December										
Developed	**382**	**300**	**7,168**	**18**	**3,581**	**1,301**	**4,674**	**1,748**	**3,316**	**22,487**
Undeveloped	**386**	**19**	**2,447**	**1**	**7,030**	**1,597**	**5,111**	**3,901**	**1,719**	**22,209**
	768	**318**	**9,615**	**18**	**10,610**	**2,897**	**9,785**	**5,648**	**5,035**	**44,695**

[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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] Includes 181 billion cubic feet of natural gas consumed in operations, 151 billion cubic feet in subsidiaries, 29 billion cubic feet in equity-accounted entities.

[d] Includes 2,519 billion cubic feet of natural gas 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 91 billion cubic feet of natural gas in respect of the 0.18% non-controlling interest in Rosneft.

[g] Total proved gas reserves held as part of our equity interest in Rosneft is 9,827 billion cubic feet, comprising 1 billion cubic feet in Canada, 14 billion cubic feet in Venezuela, 26 billion cubic feet in Vietnam and 9,785 billion cubic feet in Russia.

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Movements in estimated net proved reserves continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]	Europe		North America		South America	Africa	Asia		Australasia	2014 Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	(91)	(78)	96	(14)	(36)	(1)		90	(62)	(96)
Improved recovery	3		129		39	8				180
Purchases of reserves-in-place	6		1					68		74
Discoveries and extensions	21		1		47	1		54		123
Production[e f]	(23)	(24)	(258)	(1)	(146)	(121)		(86)	(60)	(717)
Sales of reserves-in-place			(109)		(5)					(114)
	(84)	(101)	(140)	(14)	(99)	(113)		126	(122)	(548)
At 31 December[g]										
Developed	232	160	2,588	12	426	477		675	618	5,187
Undeveloped	398	26	1,191	163	1,139	403		868	319	4,507
	630	186	3,779	175	1,565	880		1,543	937	9,694
Equity-accounted entities (BP share)[h]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates					(11)	4	276	9		278
Improved recovery					16					16
Purchases of reserves-in-place										
Discoveries and extensions					22		219			241

Production[f]					**(56)**	**(1)**	**(365)**	**(39)**		**(460)**
Sales of reserves-in-place					**(29)**	**3**	**130**	**(29)**		**75**
At 31 December[i j]										
Developed					**528**	**86**	**3,834**	**100**		**4,548**
Undeveloped				**1**	**438**		**2,830**	**13**		**3,280**
				1	**965**	**86**	**6,663**	**112**		**7,828**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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**
At 31 December										
Developed	**232**	**160**	**2,588**	**12**	**954**	**563**	**3,834**	**775**	**618**	**9,735**
Undeveloped	**398**	**26**	**1,191**	**164**	**1,576**	**403**	**2,830**	**881**	**319**	**7,788**
	630	**186**	**3,779**	**176**	**2,530**	**966**	**6,663**	**1,656**	**937**	**17,523**

[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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 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.

[e] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.

[f] 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.

[g] Includes 456 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[i] Includes 54 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.

[j] Total proved reserves held as part of our equity interest in Rosneft is 6,702 million barrels of oil equivalent, comprising 1 million barrels of oil equivalent in Canada, 33 million barrels of oil equivalent in Venezuela, 5 million barrels of oil equivalent in Vietnam and 6,663 million barrels of oil equivalent in Russia.

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Movements in estimated net proved reserves continued

million barrels

Crude oil[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
2013	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	228	153	1,127		16	306		268	45	2,143
Undeveloped	426	73	818		20	236		137	34	1,743
	654	226	1,945		36	542		405	79	3,886
Changes attributable to										
Revisions of previous estimates	(79)	(15)	(111)		1	30		65	(5)	(114)
Improved recovery	11		33		1	2		65		112
Purchases of reserves-in-place										
Discoveries and extensions			2					39	3	44
Production	(21)	(11)	(108)		(7)	(79)		(52)	(8)	(285)
Sales of reserves-in-place	(31)		(1)							(32)
	(120)	(26)	(185)		(5)	(47)		117	(10)	(276)
At 31 December[d]										
Developed	160	147	1,007		15	316		320	49	2,013
Undeveloped	374	53	752		17	180		202	19	1,597
	534	200	1,760		31	495		522	69	3,610
Equity-accounted entities (BP share)[e f]										
At 1 January										
Developed					336	3	2,433	198		2,970
Undeveloped					347	2	1,943	13		2,305
					683	5	4,376	211		5,275
Changes attributable to										
Revisions of previous estimates				1	(14)	(1)	295	1		281
Improved recovery					27					27
Purchases of reserves-in-place					34		4,550			4,584
Discoveries and extensions					12		228			240
Production					(27)		(301)	(85)		(412)

Sales of reserves-in-place					(85)		(4,321)			(4,406)
				1	(53)	(1)	451	(84)		314
At 31 December[g]										
Developed					316	2	2,970	120		3,407
Undeveloped				1	314	2	1,858	7		2,182
				1	630	4	4,828	127		5,590
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	228	153	1,127		352	309	2,433	466	45	5,113
Undeveloped	426	73	818		367	239	1,943	150	34	4,048
	654	226	1,945		719	547	4,376	616	79	9,162
At 31 December										
Developed	160	147	1,007		331	317	2,970	440	49	5,421
Undeveloped	374	53	752	1	331	182	1,858	209	19	3,779
	534	200	1,760	1	661	499	4,828	649	69	9,200

[a] Crude oil includes 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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] 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.

[d] Includes 8 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 23 million barrels of crude oil in respect of the 0.47% non-controlling interest in Rosneft.

[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 4,860 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 32 million barrels in Venezuela and 4,827 million barrels in Russia.

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Movements in estimated net proved reserves continued

										million barrels
Natural gas liquids[a] [b]										2013
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	14	17	316		6	6			7	366
Undeveloped	5	6	171		12	19			11	225
	19	23	487		18	25			18	591
Changes attributable to										
Revisions of previous estimates	1	(4)	(30)		29	(4)			(7)	(15)
Improved recovery	1		19							20
Purchases of reserves-in-place										
Discoveries and extensions			2							2
Production[c]	(1)	(1)	(24)		(4)	(1)			(1)	(33)
Sales of reserves-in-place	(5)		(10)							(15)
	(4)	(5)	(43)		25	(5)			(8)	(40)
At 31 December[d]										
Developed	9	16	290		14	4			8	342
Undeveloped	6	2	155		28	15			3	209
	15	18	444		43	20			10	551
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed					3	9	59			71
Undeveloped					4	9	19			32
					7	18	78			103
Changes attributable to										
Revisions of previous estimates					(7)	(2)	89			81
Improved recovery										
Purchases of reserves-in-place							29			29
Discoveries and extensions										
Production							(2)			(3)
Sales of reserves-in-place							(78)			(78)
					(7)	(2)	38			29
At 31 December[f]										

Developed					8	94		103
Undeveloped					8	21		29
					16	115		131
Total subsidiaries and equity-accounted entities (BP share)								
At 1 January								
Developed	14	17	316	9	15	59	7	437
Undeveloped	5	6	171	16	27	19	11	257
	19	23	487	25	43	78	18	693
At 31 December								
Developed	9	16	290	14	13	94	8	444
Undeveloped	6	2	155	28	23	21	3	238
	15	18	444	43	36	115	10	682

[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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] Excludes NGLs from processing plants in which an interest is held of 5,500 barrels per day.

[d] Includes 13 million barrels of NGL 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] Total proved NGL reserves held as part of our equity interest in Rosneft is 115 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 115 million barrels in Russia.

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Movements in estimated net proved reserves continued

		million barrels
Bitumen[a b]		2013
	Rest of North America	Total
Subsidiaries		
At 1 January		
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		
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.

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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Movements in estimated net proved reserves continued

million barrels

Total liquids[a b]										2013
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	242	170	1,444		22	312		268	52	2,509
Undeveloped	431	79	989	195	32	255		137	45	2,164
	673	249	2,433	195	54	567		405	96	4,673
Changes attributable to										
Revisions of previous estimates	(78)	(19)	(141)	(7)	30	26		65	(12)	(136)
Improved recovery	12		52		1	2		65		132
Purchases of reserves-in-place										
Discoveries and extensions			3					39	3	45
Production[d]	(22)	(13)	(132)		(11)	(80)		(52)	(9)	(319)
Sales of reserves-in-place	(36)		(12)							(48)
	(124)	(31)	(229)	(7)	20	(52)		117	(18)	(324)
At 31 December[e]										
Developed	169	163	1,297		29	320		320	57	2,354
Undeveloped	380	55	907	188	46	195		202	22	1,994
	549	217	2,204	188	74	515		523	78	4,348
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed					339	12	2,492	198		3,041
Undeveloped					351	11	1,962	13		2,337
					691	23	4,453	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					11		228			239
Production					(27)		(302)	(85)		(414)

Sales of reserves-in-place					(85)		(4,399)			(4,485)
				1	(61)	(3)	490	(84)		343
At 31 December[g h]										
Developed					316	10	3,063	120		3,510
Undeveloped				1	314	10	1,879	7		2,210
				1	630	20	4,943	127		5,721
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	242	170	1,444		361	324	2,492	466	52	5,550
Undeveloped	431	79	989	195	384	266	1,962	150	45	4,501
	673	249	2,433	195	745	590	4,453	616	96	10,051
At 31 December										
Developed	169	163	1,297		345	331	3,063	440	57	5,865
Undeveloped	380	55	907	188	359	205	1,879	209	22	4,204
	549	217	2,204	189	704	535	4,943	650	78	10,069

[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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] 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.

[d] Excludes NGLs from processing plants in which an interest is held of 5,500 barrels per day.

[e] Also includes 21 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[g] Includes 23 million barrels in respect of the non-controlling interest in Rosneft.

[h] Total proved liquid reserves held as part of our equity interest in Rosneft is 4,975 million barrels, comprising 1 million barrels in Canada, 32 million barrels in Venezuela, less than 1 million barrels in Vietnam and 4,943 million barrels in Russia.

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Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a b]	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	(62)	(47)	(1,166)	10	62	(138)		2,148	(140)	667
Improved recovery	49		630		144	28		94		945
Purchases of reserves-in-place	9									9
Discoveries and extensions			39			55		1,875	511	2,480
Production[c]	(66)	(31)	(635)	(4)	(819)	(239)		(199)	(289)	(2,282)
Sales of reserves-in-place	(677)		(152)					(67)		(896)
	(747)	(78)	(1,284)	6	(613)	(294)		3,851	82	923
At 31 December[d]										
Developed	643	364	7,122	10	3,109	961		1,519	3,932	17,660
Undeveloped	314	39	2,825		6,116	1,807		3,671	1,755	16,527
	957	403	9,947	10	9,225	2,768		5,190	5,687	34,187
Equity-accounted entities (BP share)[e]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates				1	3	29	685	1		719
Improved recovery					64			3		67
Purchases of reserves-in-place					14		8,871	33		8,918
					51		254			305

Discoveries and extensions										
Production[c]					(163)	(3)	(292)	(23)		(481)
Sales of reserves-in-place					(38)		(4,669)	(74)		(4,781)
				1	(69)	26	4,849	(60)		4,747
At 31 December[f g]										
Developed					1,364	230	4,171	72		5,837
Undeveloped				1	747	135	5,054	14		5,951
				1	2,111	365	9,225	86		11,788
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	643	364	7,122	10	4,473	1,191	4,171	1,591	3,932	23,497
Undeveloped	314	39	2,825	1	6,863	1,942	5,054	3,685	1,755	22,478
	957	403	9,947	11	11,336	3,133	9,225	5,276	5,687	45,975

[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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] 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.

[d] Includes 2,685 billion cubic feet of natural gas 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 41 billion cubic feet of natural gas in respect of the 0.44% non-controlling interest in Rosneft.

[g] 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.

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Movements in estimated net proved reserves continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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[e f]	(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[g]										
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)[h]										
At 1 January										
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[f]					(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[i j]										
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										
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										
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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

[d] 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.

[e] Excludes NGLs from processing plants in which an interest is held of 5,500 barrels of oil equivalent per day.

[f] 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.

[g] Includes 484 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[i] Includes 30 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.

[j] 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.

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Movements in estimated net proved reserves continued

million barrels

Crude oil[a b]	UK	Europe: Rest of Europe	North America: US	North America: Rest of North America	South America	Africa	Asia: Russia	Asia: Rest of Asia	Australasia	2012 Total
Subsidiaries										
At 1 January										
Developed	276	66	1,337		23	304		176	50	2,233
Undeveloped	436	208	1,021		30	294		279	36	2,304
	712	274	2,357		53	598		455	86	4,537
Changes attributable to										
Revisions of previous estimates	(30)	(23)	(288)		(11)	(1)		(2)		(354)
Improved recovery	3		77			13		2		95
Purchases of reserves-in-place	4		4							8
Discoveries and extensions		1	10			2				12
Production	(30)	(8)	(115)		(6)	(70)		(51)	(8)	(287)
Sales of reserves-in-place	(6)	(18)	(101)							(124)
	(59)	(48)	(412)		(17)	(56)		(51)	(8)	(650)
At 31 December[d e]										
Developed	228	153	1,127		16	306		268	45	2,143
Undeveloped	426	73	818		20	236		137	34	1,743
	654	226	1,945		36	542		405	79	3,886
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed					345		2,596	256		3,197
Undeveloped					344	3	1,613	58		2,018
					689	3	4,209	314		5,215
Changes attributable to										
Revisions of previous estimates					(2)	3	377	(23)		355
Improved recovery					24		47			71
Purchases of reserves-in-place										

Discoveries and extensions						67			67
Production				(29)		(309)	(80)		(418)
Sales of reserves-in-place						(15)			(15)
				(7)	3	167	(103)		60
At 31 December[g h i]									
Developed				336	3	2,433	198		2,970
Undeveloped				347	2	1,943	13		2,305
				683	5	4,376	211		5,275
Total subsidiaries and equity-accounted entities (BP share)									
At 1 January									
Developed	276	66	1,337	368	304	2,596	432	50	5,430
Undeveloped	436	208	1,021	375	297	1,613	337	36	4,322
	712	274	2,357	743	601	4,209	769	86	9,752
At 31 December									
Developed	228	153	1,127	352	309	2,433	466	45	5,113
Undeveloped	426	73	818	367	239	1,943	150	34	4,048
	654	226	1,945	719	547	4,376	616	79	9,162

[a] Crude oil includes 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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] 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.

[d] Includes 9 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[e] Includes assets held for sale of 39 million barrels.

[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[g] Includes 328 million barrels of crude oil in respect of the 7.35% non-controlling interest in TNK-BP.

[h] Total proved crude oil reserves held as part of our equity interest in TNK-BP is 4,463 million barrels, comprising 87 million barrels in Venezuela and 4,376 million barrels in Russia.

[i] Includes assets held for sale of 4,463 million barrels.

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Movements in estimated net proved reserves continued

million barrels

Natural gas liquids[a b]	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										
Developed	12	3	348		4	7		1	9	383
Undeveloped	9	22	152		18	21			11	233
	21	25	501		22	28		1	20	616
Changes attributable to										
Revisions of previous estimates		(2)	8							5
Improved recovery			63							63
Purchases of reserves-in-place			17							17
Discoveries and extensions			13							14
Production[c]	(1)		(27)		(4)	(3)			(1)	(37)
Sales of reserves-in-place			(87)							(88)
	(1)	(2)	(14)		(4)	(3)			(1)	(26)
At 31 December[d]										
Developed	14	17	316		6	6			7	366
Undeveloped	5	6	171		12	19			11	225
	19	23	487		18	25			18	591
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed					4					4
Undeveloped					4	11				15
					8	11				19
Changes attributable to										
Revisions of previous estimates						6	85			91
Improved recovery										
Purchases of reserves-in-place										
Discoveries and extensions										
Production							(7)			(7)
Sales of reserves-in-place										
						6	78			84
At 31 December[f g]										
Developed					3	9	59			71

Undeveloped					4	9	19			32
					7	18	78			103
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	12	3	348		8	7		1	9	387
Undeveloped	9	22	152		21	32			11	248
	21	25	501		29	39		1	20	635
At 31 December										
Developed	14	17	316		9	15	59		7	437
Undeveloped	5	6	171		16	27	19		11	257
	19	23	487		25	43	78		18	693

[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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] Excludes NGLs from processing plants in which an interest is held of 13,500 barrels per day.

[d] Includes 5 million barrels of NGL 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] Total proved NGL reserves held as part of our equity interest in TNK-BP is 78 million barrels, all in Russia.

[g] Includes assets held for sale of 78 million barrels.

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Movements in estimated net proved reserves continued

		million barrels
Bitumen[a b]		2012
	Rest of North America	Total
Subsidiaries		
At 1 January		
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		
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.

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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Movements in estimated net proved reserves continued

million barrels

Total liquids[a b]	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										
Developed	287	69	1,686		27	311		177	59	2,617
Undeveloped	445	230	1,173	178	48	314		279	47	2,714
	733	299	2,859	178	75	625		456	106	5,331
Changes attributable to										
Revisions of previous estimates	(29)	(25)	(280)	18	(11)	(1)		(2)		(331)
Improved recovery	3		140			13		2		158
Purchases of reserves-in-place	4		21							24
Discoveries and extensions		1	23			2				26
Production[d]	(31)	(8)	(141)		(10)	(72)		(51)	(9)	(324)
Sales of reserves-in-place	(6)	(18)	(188)							(212)
	(59)	(51)	(425)	18	(21)	(59)		(51)	(10)	(658)
At 31 December[e f]										
Developed	242	170	1,444		22	312		268	52	2,509
Undeveloped	431	79	989	195	32	255		137	45	2,164
	673	249	2,433	195	54	567		405	96	4,673
Equity-accounted entities (BP share)[g]										
At 1 January										
Developed					349		2,595	256		3,201
Undeveloped					348	14	1,614	58		2,034
					697	14	4,209	314		5,234
Changes attributable to										
Revisions of previous estimates					(2)	9	462	(24)		445
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	244	(103)		144

At 31 December[h,i,j]										
Developed					339	12	2,492	198		3,041
Undeveloped					351	11	1,962	13		2,337
					691	23	4,453	211		5,378
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	287	69	1,686		376	311	2,595	433	59	5,817
Undeveloped	445	230	1,173	178	396	328	1,614	337	47	4,748
	733	299	2,859	178	772	640	4,209	770	106	10,565
At 31 December										
Developed	242	170	1,444		361	324	2,492	466	52	5,550
Undeveloped	431	79	989	195	384	266	1,962	150	45	4,501
	673	249	2,433	195	745	590	4,453	616	96	10,051

[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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[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] Also includes 14 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[f] Includes assets held for sale of 4,540 million barrels.

[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[h] Includes 328 million barrels in respect of the non-controlling interest in TNK-BP.

[i] 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.

[j] Includes assets held for sale of 39 million barrels.

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Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a b]	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										
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[c]	(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[d e]										
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)[f]										
At 1 January										
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[c]					(169)		(280)	(35)		(484)
Sales of reserves-in-place							(1)			(1)
					30	144	1,598	(9)		1,763
At 31 December[g h i]										
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										
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										
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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] 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.

[d] Includes 2,890 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[e] Includes assets held for sale of 590 billion cubic feet.

[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[g] Includes 270 billion cubic feet of natural gas in respect of the 6.17% non-controlling interest in TNK-BP.

[h] 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.

[i] Includes assets held for sale of 4,492 billion cubic feet.

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Movements in estimated net proved reserves continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]										2012
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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[e f]	(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[g h]										
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)[i]										
At 1 January										
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[e f]					(58)		(364)	(86)		(508)
Sales of reserves-in-place							(15)			(15)
					(1)	34	520	(105)		448
At 31 December[j k l]										
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										
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										
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] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

[d] 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.

[e] Excludes NGLs from processing plants in which an interest is held of 13,500 barrels of oil equivalent per day.

[f] 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.

[g] 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.

[h] Includes assets held for sale of 140 million barrels of oil equivalent.

[i] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[j] Includes 103 million barrels of NGLs. Also includes 374 million barrels of oil equivalent in respect of the non-controlling interest in TNK-BP.

[k] 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.

[l] Includes assets held for sale of 5,315 million barrels of oil equivalent.

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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.

$ millio

	Europe		North America		South America	Africa	Asia		Australasia	201 Tota
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	**54,400**	**14,900**	**216,600**	**11,000**	**35,300**	**55,800**		**90,300**	**54,800**	**533,10**
Future production cost[b]	**21,400**	**8,100**	**90,500**	**4,800**	**11,300**	**15,600**		**41,500**	**17,600**	**210,80**
Future development cost[b]	**7,300**	**1,400**	**24,500**	**1,600**	**8,000**	**9,600**		**23,000**	**5,700**	**81,10**
Future taxation[c]	**16,400**	**3,000**	**32,900**	**700**	**8,400**	**10,100**		**5,100**	**9,400**	**86,00**
Future net cash flows	**9,300**	**2,400**	**68,700**	**3,900**	**7,600**	**20,500**		**20,700**	**22,100**	**155,20**
10% annual discount[d]	**4,700**	**700**	**33,100**	**2,500**	**3,100**	**7,800**		**11,000**	**11,800**	**74,70**
Standardized measure of discounted future net cash flows[e]	**4,600**	**1,700**	**35,600**	**1,400**	**4,500**	**12,700**		**9,700**	**10,300**	**80,50**

Equity-accounted entities (BP share)[f]										
Future cash inflows[a]					**47,300**		**349,200**	**10,200**		**406,70**
Future production cost[b]					**22,300**		**200,000**	**7,800**		**230,10**
Future development cost[b]					**5,700**		**17,400**	**2,100**		**25,20**
Future taxation[c]					**6,700**		**24,200**	**100**		**31,00**
Future net cash flows					**12,600**		**107,600**	**200**		**120,40**
10% annual discount[d]					**8,000**		**65,500**			**73,50**
Standardized measure of discounted future net cash flows[g h]					**4,600**		**42,100**	**200**		**46,90**
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	**4,600**	**1,700**	**35,600**	**1,400**	**9,100**	**12,700**	**42,100**	**9,900**	**10,300**	**127,40**

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	**(30,500)**	**(6,900)**	**(37,400)**
Development costs for the current year as estimated in previous year	**15,700**	**3,600**	**19,300**
Extensions, discoveries and improved recovery, less related costs	**1,900**	**1,500**	**3,400**
Net changes in prices and production cost	**(17,000)**	**10,500**	**(6,500)**
Revisions of previous reserves estimates	**1,200**	**2,000**	**3,200**
Net change in taxation	**17,300**	**(4,900)**	**12,400**
Future development costs	**(4,500)**	**(400)**	**(4,900)**
Net change in purchase and sales of reserves-in-place	**(700)**		**(700)**
Addition of 10% annual discount	**8,800**	**3,800**	**12,600**
Total change in the standardized measure during the year[i]	**(7,800)**	**9,200**	**1,400**

[a] The marker prices used were Brent $101.27/bbl, Henry Hub $4.31/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 interests in BP Trinidad and Tobago LLC amounted to $1,400 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 interests in Rosneft amounted to $100 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. Exchange rate effects arising from the translation of our share of Rosneft changes to US dollars are included within Net changes in prices and production cost.

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Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves continued

$ million

										2013
	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										
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 cash flows[e]	7,100	2,900	36,500	500	5,500	15,200		10,800	9,800	88,300
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
					6,900		48,700	100		55,700

10% annual discount[d]										
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 interests 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 interests 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.

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Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves continued

										$ million 2012 Total
	Europe		North America		South America	Africa	Asia		Australasia	
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
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
					12,500		43,500	1,300		57,300

Future net cash flows 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
	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(34,600)	(8,300)	(42,900)
Development costs for the current year as estimated in previous year	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 interests 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 interests 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.

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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, natural gas liquids and natural gas production for the years ended 31 December 2014, 2013 and 2012.

Production for the year[a b]

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[c]	Rest of Asia		
Subsidiaries										
Crude oil[d]										thousand barrels per day
2014	**46**	**41**	**347**		**13**	**222**		**156**	**19**	**844**
2013	58	31	305		17	217		141	21	789
2012	81	22	327		16	191		137	22	795
Natural gas liquids										thousand barrels per day
2014	**2**	**5**	**63**		**12**	**5**			**3**	**91**
2013	3	4	58		12	3		1	4	86
2012	5	1	64	1	13	7		2	4	96
Natural gas[e]										million cubic feet per day
2014	**71**	**102**	**1,519**	**10**	**2,147**	**513**		**408**	**814**	**5,585**
2013	157	80	1,539	11	2,221	561		490	784	5,845
2012	414	8	1,651	13	2,097	590		633	787	6,193
Equity-accounted entities (BP share)										
Crude oil[d]										thousand barrels per day
2014					**65**		**816**	**98**		**979**
2013					62		826	232		1,120
2012					64		857	217		1,137
Natural gas liquids										thousand barrels per day
2014					**3**	**4**	**5**			**12**
2013					3	5	11			19
2012					3	5	20			27
Natural gas[e]										million cubic feet per day
2014					**402**		**1,084**	**28**		**1,515**
2013					384		801	30		1,216
2012					390		785	26		1,200

[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] Because of rounding, some totals may not exactly agree with the sum of their component parts.

[c] Amounts reported for Russia include BP s share of Rosneft (2014, 2013), and TNK-BP (2012) worldwide activities, including insignificant amounts outside Russia.

[d] Crude oil includes condensate.

[e] Natural gas production excludes gas consumed in operations.

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the group and its equity-accounted entities had interests as at 31 December 2014. 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[a]	Rest of Asia		
Number of productive wells at 31 December 2014											
Oil wells[b]	gross	**116**	**65**	**2,407**	**119**	**4,752**	**634**	**44,548**	**936**	**12**	**53**
	net	**71**	**26**	**823**	**31**	**2,620**	**446**	**8,798**	**302**	**2**	**13**
Gas wells[c]	gross	**67**	**6**	**22,676**	**363**	**728**	**139**	**383**	**833**	**61**	**25**
	net	**28**	**1**	**9,339**	**180**	**262**	**53**	**76**	**314**	**13**	**10**
Oil and natural gas acreage at 31 December 2014											Thousan
Developed	gross	**131**	**39**	**6,355**	**232**	**1,365**	**637**	**4,581**	**837**	**194**	**14**
	net	**73**	**16**	**3,285**	**110**	**407**	**223**	**865**	**259**	**36**	**5**
Undeveloped[d]	gross	**1,208**	**1,754**	**7,378**	**9,702**	**28,183**	**33,833**	**378,899**	**6,988**	**20,050**	**487**
	net	**755**	**648**	**5,365**	**5,564**	**11,593**	**21,799**	**74,009**	**2,302**	**10,755**	**132**

[a] Based on information received from Rosneft as at 31 December 2014.

[b] Includes approximately 11,271 gross (2,237 net) multiple completion wells (more than one formation producing into the same well bore).

[c] Includes approximately 3,239 gross (1,482 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.

[d] Undeveloped acreage includes leases and concessions.

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Operational and statistical information continued

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
2014										
Exploratory										
Productive	**2.9**		**5.3**		**3.7**	**0.7**	**5.3**	**0.6**		**18.5**
Dry	**0.5**		**7.9**		**1.4**	**1.6**		**1.4**	**0.2**	**13.0**
Development										
Productive	**3.1**	**1.8**	**294.1**	**1.5**	**100.5**	**13.8**	**76.2**	**46.3**		**537.3**
Dry		**0.8**		**0.1**	**3.9**	**1.0**		**0.4**	**0.4**	**6.6**
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

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 2014. 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 2014										
Exploratory										
Gross			**7.0**		**3.0**	**6.0**			**1.0**	**17.0**
Net			**5.6**		**0.6**	**4.0**			**0.2**	**10.4**
Development										
Gross	**2.0**	**1.0**	**339.0**	**1.0**	**47.0**	**25.0**		**66.0**	**15.0**	**496.0**
Net	**1.1**	**0.4**	**119.6**	**0.1**	**17.7**	**6.6**		**22.5**	**1.4**	**169.4**

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Pages 197-206 have been removed as they do not form part of BP S Annual Report on Form 20-F as filed with the SEC.

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Selected financial information

This information, insofar as it relates to 2014, has been extracted or derived from the audited consolidated financial statements of the BP group presented on page 89. Note 1 to the financial statements includes details on the basis of preparation of these financial statements. The selected information should be read in conjunction with the audited financial statements and related notes elsewhere herein.

	$ million except per share amounts				
	2014	2013	2012	2011	2010
Income statement data					
Sales and other operating revenues	**353,568**	379,136	375,765	375,713	297,107
Underlying replacement cost (RC) profit before interest and taxation*	**20,818**	22,776	26,454	33,601	31,704
Net favourable (unfavourable) impact of non-operating items* and fair value accounting effects*	**(8,196)**	9,283	(6,091)	3,580	(37,190)
RC profit (loss) before interest and taxation*	**12,622**	32,059	20,363	37,181	(5,486)
Inventory holding gains (losses)*	**(6,210)**	(290)	(594)	2,634	1,784
Profit (loss) before interest and taxation	**6,412**	31,769	19,769	39,815	(3,702)
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(1,462)**	(1,548)	(1,638)	(1,587)	(1,605)
Taxation	**(947)**	(6,463)	(6,880)	(12,619)	1,638
Profit (loss) for the year	**4,003**	23,758	11,251	25,609	(3,669)
Profit (loss) for the year attributable to BP shareholders	**3,780**	23,451	11,017	25,212	(4,064)
Inventory holding (gains) losses, net of taxation	**4,293**	230	411	(1,800)	(1,195)
RC profit (loss) for the year attributable to BP shareholders	**8,073**	23,681	11,428	23,412	(5,259)
Non-operating items and fair value accounting effects, net of taxation	**4,063**	(10,253)	5,643	(2,242)	25,436
Underlying RC profit for the year attributable to BP shareholders	**12,136**	13,428	17,071	21,170	20,177
Per ordinary share cents					
Profit (loss) for the year attributable to BP shareholders					
Basic	**20.55**	123.87	57.89	133.35	(21.64)
Diluted	**20.42**	123.12	57.50	131.74	(21.64)
RC profit (loss) for the year attributable to BP shareholders	**43.90**	125.08	60.05	123.83	(28.01)
Underlying RC profit for the year attributable to BP shareholders	**66.00**	70.92	89.70	111.97	107.39
Dividends paid per share cents	**39.00**	36.50	33.00	28.00	14.00
pence	**23.850**	23.399	20.852	17.404	8.679
Capital expenditure and acquisitions, on an accruals basis	**23,781**	36,612	25,204	31,959	23,016
Acquisitions and asset exchanges, on an accruals basis	**420**	71	200	11,283	3,406

Organic capital expenditure*[a], on an accruals basis	**22,892**	24,600	23,950	19,580	18,218
Balance sheet data (at 31 December)					
Total assets	**284,305**	305,690	300,466	292,907	272,262
Net assets	**112,642**	130,407	119,752	112,585	95,891
Share capital	**5,023**	5,129	5,261	5,224	5,183
BP shareholders equity	**111,441**	129,302	118,546	111,568	94,987
Finance debt due after more than one year	**45,977**	40,811	38,767	35,169	30,710
Net debt to net debt plus equity*	**16.7%**	16.2%	18.7%	20.4%	21.2%
Ordinary share data[b]					Shares million
Basic weighted average number of shares	**18,385**	18,931	19,028	18,905	18,786
Diluted weighted average number of shares	**18,497**	19,046	19,158	19,136	18,998

[a] Organic capital expenditure excludes acquisitions and asset exchanges, and: in 2014 $469 million relating to the purchase of an additional 3.3% equity in Shah Deniz, Azerbaijan and the South Caucasus Pipeline; 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.

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

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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
	2014	2013	2012
Upstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**(6,576)**	(802)	3,638
Environmental and other provisions	**(60)**	(20)	(48)
Restructuring, integration and rationalization costs	**(100)**		
Fair value gain (loss) on embedded derivatives	**430**	459	347
Other[b]	**8**	(1,001)	(748)
	(6,298)	(1,364)	3,189
Downstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**(1,190)**	(348)	(2,934)
Environmental and other provisions	**(133)**	(134)	(171)
Restructuring, integration and rationalization costs	**(165)**	(15)	(32)
Fair value gain (loss) on embedded derivatives			
Other	**(82)**	(38)	(35)
	(1,570)	(535)	(3,172)
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[c]			384
		12,500	246
Rosneft			
Impairment and gain (loss) on sale of businesses and fixed assets	**225**	(35)	
Environmental and other provisions		(10)	
Restructuring, integration and rationalization costs			
Fair value gain (loss) on embedded derivatives			
Other			
	225	(45)	
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**(304)**	(196)	(282)
Environmental and other provisions	**(180)**	(241)	(261)
Restructuring, integration and rationalization costs	**(176)**	(3)	(15)
Fair value gain (loss) on embedded derivatives			
Other[d]	**(10)**	19	(240)
	(670)	(421)	(798)

Gulf of Mexico oil spill response	**(781)**	(430)	(4,995)
Total before interest and taxation	**(9,094)**	9,705	(5,530)
Finance costs[e]	**(38)**	(39)	(19)
Taxation credit (charge)[f]	**4,512**	867	251
Total after taxation	**(4,620)**	10,533	(5,298)

[a] See Financial statements Note 3 for further information on impairments.

[b] 2014 included a $395-million write-off relating to Block KG D6 in India. 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.

[c] 2012 included dividend income from TNK-BP of $709 million and a charge of $325 million to settle disputes with Alfa, Access and Renova.

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

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

[f] From 2014, tax is based on statutory rates except for non-deductible or non-taxable items. For earlier periods tax for the Gulf of Mexico oil spill and certain impairment losses, disposal gains and fair value gains and losses on embedded derivatives, 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). For dividends received from TNK-BP in 2012, there is no tax arising. Non-operating items reported within the equity-accounted earnings of Rosneft and TNK-BP are reported net of income 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 set out below. Further information on fair value accounting effects is provided on page 253.

			$ million
	2014	2013	2012
Upstream			
Unrecognized gains (losses) brought forward from previous period	**(160)**	(404)	(538)
Unrecognized (gains) losses carried forward	**191**	160	404
Favourable (unfavourable) impact relative to management s measure of performance	**31**	(244)	(134)
Downstream[a]			
Unrecognized gains (losses) brought forward from previous period	**679**	501	74
Unrecognized (gains) losses carried forward	**188**	(679)	(501)
Favourable (unfavourable) impact relative to management s measure of performance	**867**	(178)	(427)
	898	(422)	(561)
Taxation credit (charge)[b]	**(341)**	142	216
	557	(280)	(345)
By region			
Upstream			
US	**23**	(269)	(67)
Non-US	**8**	25	(67)
	31	(244)	(134)
Downstream[a]			
US	**914**	(211)	(441)
Non-US	**(47)**	33	14
	867	(178)	(427)

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

[b] From 2014, tax is calculated using statutory rates. For earlier periods tax is calculated using the group s discrete quarterly effective tax rate (adjusted for certain non-operating items, equity-accounted earnings and certain deferred tax adjustments relating to changes in UK taxation).

Reconciliation of non-GAAP information

			$ million
	2014	2013	2012
Upstream			
RC profit before interest and tax adjusted for fair value accounting effects	**8,903**	16,901	22,625
Impact of fair value accounting effects	**31**	(244)	(134)

RC profit before interest and tax	**8,934**	16,657	22,491
Downstream			
RC profit before interest and tax adjusted for fair value accounting effects	**2,871**	3,097	3,291
Impact of fair value accounting effects	**867**	(178)	(427)
RC profit before interest and tax	**3,738**	2,919	2,864
Total group			
Profit before interest and tax adjusted for fair value accounting effects	**5,514**	32,191	20,330
Impact of fair value accounting effects	**898**	(422)	(561)
Profit before interest and tax	**6,412**	31,769	19,769

Operating capital employed*

	$ million
	2014
Upstream	**107,524**
Downstream	**38,878**
TNK-BP	
Rosneft	**7,312**
Other businesses and corporate	**20,689**
Gulf of Mexico oil spill response	**(7,986)**
Consolidation adjustment - UPII*	**(31)**
Total operating capital employed	**166,386**
Liabilities for current and deferred taxation	**(12,758)**
Goodwill	**11,868**
Finance debt	**(52,854)**
Net assets	**112,642**

Liquidity and capital resources

Financial framework

We maintain our financial framework to support the pursuit of value growth for shareholders, while ensuring a secure financial base. BP s objective over time is to grow sustainable free cash flow* through a combination of material growth in underlying operating cash flow* and a strong focus on capital discipline, providing a sound platform to grow shareholder distributions. The priority is to grow dividend per share progressively in accordance with the growth in sustainable underlying operating cash flow from our businesses over time. Any surplus cash over and above that required for capital investment and dividend payments will be biased towards further shareholder distributions through buybacks or other mechanisms.

In the near term, and reflecting the weaker oil price environment, the focus is to manage the business through a period of low oil prices and support the dividend, which remains a priority. We aim to achieve this by completing the $10-billion divestment programme (announced in the fourth quarter of 2013), re-sizing the cost base and re-setting capital expenditure to $20 billion, from the previously advised level of $24-26 billion.

We aim to operate within a gearing* range of 10-20% and maintain a significant liquidity buffer. As well as uncertainties relating to current lower oil prices, the group also faces uncertainties relating to the Gulf of Mexico oil spill as explained in Financing the group s activities below.

Dividends and other distributions to shareholders

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 increased by 43% to 10 cents per share paid in the fourth quarter of 2014. The dividend level is reviewed by the board in the first and third quarter of each year.

The total dividend paid in cash to BP shareholders in 2014 was $5.9 billion (2013 $5.4 billion) with shareholders also having the option to receive a scrip dividend. 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 initial buyback programme completed during the third quarter of 2014. Further surplus cash, beyond capital and dividend payments, was applied to additional buybacks, such that total cash paid for share buybacks in 2014 was $4.8 billion (2013 $5.5 billion). Details of share repurchases to satisfy the requirements of certain employee share-based payment plans are set out on page 250.

Financing the group s activities

The group s principal commodities, oil and gas, are 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 48 for further information on risks associated with prices and markets and Financial statements Note 27.

The group s gross debt at 31 December 2014 amounted to $52.9 billion (2013 $48.2 billion). Of the total gross debt, $6.9 billion is classified as short term at the end of 2014 (2013 $7.4 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. See Financial statements Note 24 for more information on the short-term balance.

Standard & Poor s Ratings Services changed BP s long-term credit rating to A (negative outlook) from A (positive outlook) and Moody s Investors Service rating changed to A2 (negative outlook) from A2 (stable outlook) during 2014.

Net debt was $22.6 billion at the end of 2014 a reduction of $2.6 billion from the 2013 year-end position of $25.2 billion. The ratio of net debt to net debt plus equity* was 16.7% at the end of 2014 (2013 16.2%). See Financial statements Note 25 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 $29.8 billion at 31 December 2014 (2013 $22.5 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.

The group also has undrawn committed bank facilities of $7.4 billion (see Financial statements Note 27 for more information).

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.

The group s sources of funding, its access to capital markets and maintaining a strong cash position are described in Financial statements Note 23 and Note 27. Further information on the management of liquidity risk and credit risk, and the maturity profile and fixed/floating rate characteristics of the group s debt are also provided in Financial statements Note 24 and Note 27.

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 48 and Financial statements Note 2 for further information.

Off-balance sheet arrangements

At 31 December 2014, the group s share of third-party finance debt of equity-accounted entities was $14.7 billion (2013 $17.0 billion). 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 2014 were $83 million (2013 $199 million) in respect of liabilities of joint ventures* and associates* and $244 million (2013 $305 million) in respect of liabilities of other third parties. Of these amounts, $64 million (2013 $115 million) of the joint ventures and associates guarantees relate to borrowings and for other third-party guarantees, $126 million (2013 $143 million) relate to guarantees of borrowings. Details of operating lease commitments, which are not recognized on the balance sheet, are shown in the table below and provided in Financial statements Note 26.

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Contractual obligations

The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2014 and the proportion of that expenditure for which contracts have been placed.

							$ million
							Payments due by period
Capital expenditure	Total	2015	2016	2017	2018	2019	2020 and thereafter
Committed	39,708	18,009	9,591	5,445	3,483	2,265	915
of which is contracted	15,635	8,061	3,441	2,163	1,423	442	105

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 2014, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $2,068 million. Contracts were in place for $2,025 million of this total.

The following table summarizes the group s principal contractual obligations at 31 December 2014, distinguishing between those for which a liability is recognized on the balance sheet and those for which no liability is recognized. Further information on borrowings is given in Financial statements Note 24 and more information on operating leases is given in Financial statements Note 26.

							$ million
							Payments due by period
Expected payments by period under contractual obligations	Total	2015	2016	2017	2018	2019	2020 and thereafter
Balance sheet obligations							
Borrowings[a]	56,161	7,653	6,981	6,220	5,702	6,437	23,168
Finance lease future minimum lease payments[b]	1,722	116	106	104	102	98	1,196
Decommissioning liabilities[c]	21,591	1,076	896	689	813	733	17,384
Environmental liabilities[c]	2,908	935	349	603	208	178	635
Pensions and other post-retirement benefits[d]	27,282	1,880	1,871	1,864	1,858	2,099	17,710
	109,664	11,660	10,203	9,480	8,683	9,545	60,093
Off-balance sheet obligations							
Operating lease future minimum lease payments[e]	18,785	5,401	4,047	2,682	1,857	1,330	3,468
Unconditional purchase obligations[f]	166,250	69,805	19,164	12,193	10,703	9,442	44,943
	185,035	75,206	23,211	14,875	12,560	10,772	48,411
Total	294,699	86,866	33,414	24,355	21,243	20,317	108,504

[a] Expected payments include interest totalling $4,090 million ($822 million in 2015, $711 million in 2016, $610 million in 2017, $519 million in 2018, $424 million in 2019 and $1,004 million thereafter).

[b] Expected payments include interest totalling $939 million ($70 million in 2015, $65 million in 2016, $62 million in 2017, $59 million in 2018, $55 million in 2019 and $628 million thereafter).

[c] The amounts are undiscounted. Environmental liabilities include those relating to the Gulf of Mexico oil spill.

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

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

[f] Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms (such as fixed or minimum purchase volumes, timing of purchase and pricing provisions). Agreements that do not specify all significant terms, or that are not enforceable, are excluded. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2015 include purchase commitments existing at 31 December 2014 entered into principally to meet the group s short-term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Financial statements Note 27.

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

$ million

	Payments due by period						
Unconditional purchase obligations	Total	2015	2016	2017	2018	2019	2020 and thereafter
Crude oil and oil products	78,063	43,714	9,723	5,418	4,725	3,530	10,953
Natural gas	29,982	17,741	4,245	2,552	2,090	1,604	1,750
Chemicals and other refinery feedstocks	12,836	3,097	2,508	2,145	2,192	2,228	666
Power	3,610	2,425	759	262	74	28	62
Utilities	731	219	167	108	97	50	90
Transportation	21,799	1,423	1,013	1,062	1,064	926	16,311
Use of facilities and services	19,229	1,186	749	646	461	1,076	15,111
Total	166,250	69,805	19,164	12,193	10,703	9,442	44,943

The information above 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 the cautionary statement on page 241 and Risk factors on page 48, 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.

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Upstream analysis by region

Our upstream operations are listed by geographical area, with associated significant events for 2014. BP s percentage working interest in oil and gas assets is shown in parenthesis. 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 20% 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. In September, BP and Tokyo Electric Power Company (TEPCO) signed an agreement for TEPCO to purchase up to 1.2 million tonnes of LNG per year from BP for 17 years starting in 2017.

Europe

BP is active in the North Sea and the Norwegian Sea. Our activities focus on maximizing recovery from existing producing fields and selected new field developments. BP s production is generated from three key areas; the Shetland Area comprising Magnus, Clair, Foinaven and Schiehallion fields; the Central Area comprising Bruce, Andrew and ETAP fields; and Norway, comprising Valhall, Ula and Skarv fields.

In March 2013 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 (BP 28.6%), west of the Shetland Islands. By the end of 2014, five of the planned six appraisal wells had been completed, with drilling started on the sixth well.

Activity continued on the major redevelopment of the Schiehallion and Loyal fields to the west of Shetland during 2014. Following work to preserve the existing wells and subsea infrastructure, the risers and moorings were disconnected, allowing the Schiehallion floating production storage and offloading unit (FPSO) to be towed off-station in May. Construction continues on the replacement FPSO, the Glen Lyon.

Operations at the Rhum gas field recommenced in October under a temporary management scheme announced by the UK government in 2013. Production had 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. See International trade sanctions on page 238.

BP announced the Vorlich discovery in the central North Sea in October. It spans the GDF SUEZ E&P UK Ltd-operated block 30/1f and the BP-operated (BP 50%) block 30/1c.

Production started up from the Kinnoull field (BP 77.06%) in the central North Sea in December. The Kinnoull reservoir, developed as part of a wider rejuvenation of the Andrew field area, is tied back to BP s Andrew platform and will enable production there to be extended. BP has been granted three licences in the UK government s 28th licensing round. The licences are located in three of our core areas: to the north of our Magnus field in the northern North Sea; next to our recent Vorlich discovery; and west of our Kinnoull development. The government is still to award some licences in this round as they are undergoing environmental assessment.

In December, a number of North Sea fields were subject to impairment charges, primarily as a result of reductions in proved reserves, decreases in short-term oil and gas price assumptions and increases in expected decommissioning cost estimates. The total impairment charge for 2014 was $4,774 million, of which $1,964 million related to the Valhall asset, $660 million related to the Andrew area assets, and $515 million related to the ETAP asset. There were a number of other impairment charges that were not individually significant.

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 around 80 fields in the central North Sea. The system has a capacity of more than 675mboe/d, with average throughput in 2014 of 363mboe/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 providing transport and processing services. The pipeline has a transportation capacity of 293mboe/d to a natural gas terminal at Teesside in north-east England. Average throughput in 2014 was 134mboe/d. BP also operates the Sullom Voe oil and gas terminal in Shetland. In December, BP announced the intent to sell our equity in the CATS business.

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 36.

BP has around 600 lease blocks in the deepwater Gulf of Mexico, more than any other company, and operates four production hubs.

BP had 10 rigs in the Gulf of Mexico at the end of 2014.

The BP-operated Na Kika Phase 3 project (BP 50%) and the Shell-operated Mars B major project (BP 28.5%) started up in February. A second Na Kika Phase 3 well started up in April.

The Atlantis North expansion Phase 2 major project (BP 56%) started up in April.

BP announced an oil discovery at the Guadalupe prospect (BP 42.5%) in the deepwater Gulf of Mexico in October. Project operator Chevron drilled the discovery well on Keathley Canyon block 10 on behalf of the Guadalupe co-owners. The well encountered significant economically producible hydrocarbons in Paleogene age Wilcox Sands.

In January 2015 BP announced it had formed a new ownership and operating model with Chevron and ConocoPhillips to focus on moving two significant BP Paleogene discoveries closer to development and provide expanded exploration access in the deepwater Gulf of Mexico. BP sold approximately half of its current equity interests in the Gila field to Chevron in December and sold approximately half of its equity interest in the Tiber field in January 2015. BP, Chevron and ConocoPhillips also have agreed to joint ownership interests in exploration blocks east of Gila known as Gibson, where they plan to drill in 2015. As a result of the agreements, BP, Chevron and ConocoPhillips will have the same working interests across Gila and Gibson and any future centralized production facility. Chevron will hold equity interest of 36%, BP 34% and ConocoPhillips 30%. In Tiber, BP and Chevron will each hold equity interest of 31%, Petrobras 20% and ConocoPhillips 18%. Chevron will operate Tiber, Gila and Gibson. Operatorship is expected to be transferred after BP finishes drilling appraisal wells at Gila and Tiber. BP believes combining the technical strengths and financial resources of these three companies will provide greater efficiency through scale, reduce subsurface risk and increase the likelihood of achieving a future commercial development.

BP was the apparent high bidder in 27 out of 32 blocks in the Gulf of Mexico western lease sales in August, all of which have been awarded. This is in addition to 24 blocks awarded in the Gulf of Mexico in March lease sales. See also Significant estimate or judgement: oil and natural gas accounting on page 102 for further information on leases.

The US Lower 48 onshore business has significant activities producing natural gas, NGLs and condensate across seven states, including production from unconventional gas, coalbed methane (CBM) and shale gas assets.

BP has an extensive resource base across 3.0 million net (5.5 million gross) developed acres and over 22,815 gross wells, with daily production around 300mboe/d. We believe there is potential to unlock significant value from this resource base and we have decades of experience in the necessary technologies.

Starting in 2015 our US Lower 48 onshore business began operating as a separate business, with its own governance, processes and systems. This is designed to promote faster decision making and adoption of innovation so that BP can be more competitive in the US onshore market. David Lawler was named chief executive officer in August.

BP and Pantera Acquisition Group, LLC (Pantera) signed an agreement under which Pantera agreed to acquire BP s interests in the Panhandle West and Texas Hugoton gas fields for a purchase price of $390 million in June. See page 26 for more information.

Following on from the decision to create a separate BP business around our US Lower 48 onshore oil and gas activities, and as a consequence of disappointing appraisal results, we decided not to proceed with development plans in the Utica shale, incurring a $544-million write-off relating to this acreage.

For further information on the use of hydraulic fracturing in our shale gas assets see page 43. BP s onshore US crude oil and product pipelines and related transportation assets are included in the Downstream segment.

In Alaska, at the end of 2014, BP operated nine North Slope oilfields in the Greater Prudhoe Bay area and owned significant interests in six producing fields operated by others. BP also owns significant non-operating interests in the Point Thomson development project and the Liberty prospect.

In April BP announced the agreement to sell interests in four BP-operated oilfields on the North Slope of Alaska to Hilcorp. The sale agreement included all of BP s interests in the Endicott and Northstar oilfields and a 50% interest in each of the Milne Point field and the Liberty prospect, together with BP s interests in the oil and gas pipelines associated with these fields. The sales price was $1.25 billion plus an additional carry of up to $250 million if the Liberty field is developed. The sale completed in November. See page 26 for more information.

Development of the Point Thomson initial production facility continued throughout 2014. Engineering design is complete and construction of field infrastructure and fabrication of the four main process modules is in progress. Overall, the project is on track to commence production in 2016. BP holds a 32% working interest in the field, and ExxonMobil is the operator.

BP continued to work jointly with ExxonMobil, ConocoPhillips, TransCanada, the Alaska Gasline Development Corporation and the State of Alaska throughout 2014 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 (up to 20 million tonnes per annum). In October 2013 selection of the lead site for the liquefaction facility was announced as Nikiski, Alaska, located on the south-central Alaskan coast. In January BP, ExxonMobil, ConocoPhillips and TransCanada, and the Alaska Gasline Development Corporation 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, and provided a roadmap for State of Alaska participation in the project. In April the Alaska Legislature passed legislation (SB-138) which approved State participation in the project as a 25% co-investor, and allowed payment of gas production tax in the form of gas volumes. On 30 June 2014 the Alaska LNG co-venturers, including the State of Alaska, executed commercial agreements and launched the pre-front end engineering and design (pre-FEED) phase of the project, which is expected to extend into 2016 with gross spend more than $500 million. A decision point for progressing to front end engineering and design (FEED) phase of the project will be considered at the completion of the pre-FEED phase. In July the Alaska LNG project submitted an export application with the US Department of Energy, and in September submitted a pre-file notice of application with the Federal Energy Regulatory Commission (FERC), which was approved by the FERC later that month. The US Department of Energy issued a Free Trade Agreement Export Authorization to the project in November. First commercial gas is planned between 2023 and 2025.

BP owns a 49% 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 related litigation will continue in 2015.

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 offshore exploration interests in the Canadian Beaufort Sea and in Nova Scotia.

- Phase 1 of the Sunrise Oil Sands SAGD development, in which BP has a 50% non-operated interest, achieved first steam in the reservoir in December 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 licenses was conducted over the summer of 2014 with 7,090km^2 of wide azimuth 3D seismic data acquired. The processing of this seismic data will be completed by the end of 2015 to identify possible exploration well locations. During the fourth quarter of 2014 BP expanded the Nova Scotia licence participation to include Hess Canada Oil and Gas ULC and Woodside Energy International (Canada). The new participating interests are BP 40% (operator), Hess 40% and Woodside 20%.

South America

BP has upstream activities in Brazil, Argentina, Bolivia, Chile, Uruguay and Trinidad & Tobago.

In Brazil, BP has interests in 22 exploration and production concessions across six basins, five of which are operated by BP. BP s entry into five of these concessions is subject to government and regulatory approvals.

- BP completed the sale of interest in the Polvo oil field (BP 60%) in Brazil to HRT Oil & Gas Ltda for $135 million in January.
- During the year BP continued appraisal of the Itaipu discovery, located in the deepwater sector of the Campos basin offshore Brazil, in line with the appraisal plan approved by the Brazilian National Petroleum Agency (ANP).
- In October the ANP approved the appraisal plan submitted by the operator, Petróleo Brasileiro S.A. (Petrobras) for BM-POT-16 and BM-POT-17 (two blocks in the deepwater Potiguar basin located in the Brazilian equatorial margin), covering activities to 2018. BP s farm-in to a 40% interest in the blocks announced in July 2013 is subject to final regulatory approvals.
- In July BP had a discovery at Xerelete (BP 18%) in Brazil s Campos basin, operated by Total.

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. BP holds a 100% interest in the blocks and the Uruguayan state oil company, ANCAP, has a right to participate in up to 30% of any discoveries. BP has already completed its commitment to acquire over 13,000km^2 of 3D seismic data and 3,000km of 2D seismic data by December 2015.

In Trinidad & Tobago, BP holds licences and production-sharing contracts covering 1.8 million acres offshore of the east and north-east coast. Facilities include 13 offshore platforms and two onshore processing facilities. Production is comprised of gas and associated liquids. In August, the Juniper project was sanctioned and subsequently a key contract for the development of the project was awarded. Fabrication began in November.

BP also has a shareholding in Atlantic LNG (ALNG), an LNG liquefication plant that averages 39% across four LNG trains[a] with a combined capacity of 15 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 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.

[a] An LNG train is a processing facility used to liquefy and purify natural gas in the formation of LNG.

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Africa

BP s upstream activities in Africa are located in Angola, Algeria, Libya, Egypt and Morocco.

In Angola, BP is present in nine major deepwater licences offshore and is operator in four of these. Two of these are in production (blocks 18 and 31), and two are in the exploration phase (blocks 19 and 24). The first exploration well on block 24 (Katambi-1) is currently being drilled.

- Following a successful drill-stem test in May, BP had another oil and gas discovery in the pre-salt play of Angola in block 20 (BP 30%) operated by Cobalt International Energy, Inc. This discovery (the Orca-1 well) is the second pre-salt discovery in block 20. The Orca-2 appraisal well is currently being drilled.
- Production commenced from the Total-operated CLOV (Cravo, Lirio, Orquidea and Violeta) major project in Angola (BP 16.67%) in June. Plateau production of 160,000 barrels of oil was achieved in September.
- In the first quarter the Angola LNG plant (BP 13.6%) produced and sold a number of LNG cargoes, along with its first LPG, pressurised butane and condensate cargoes. Following a technical incident in April 2014, which caused an unplanned interruption to production, the plant s planned shutdown was brought forward to address both technical and plant capacity issues. The plant is projected to re-start fully in 2016.
- In December, several fields in Angola were subject to impairment charges, primarily as a result of changes in estimates of reserves and resources and decreases in near-term oil price assumptions. The total impairment charge during the year was $968 million, of which the Plutão, Saturno, Vénus and Marte (PSVM) area was subject to an impairment charge of $859 million.

In Algeria, BP, Sonatrach and Statoil are partners in the In Salah (BP 33.15%) and In Amenas (BP 45.89%) projects which supply gas to the domestic and European markets. BP s total assets in Algeria at 31 December 2014 were $1,717 million ($290 million current and $1,427 million non-current).

- The security assessment following the terrorist attack in January 2013 has been completed.
- BP also had an appraisal and exploitation agreement with Sonatrach in the Bourarhat Sud block, located to the south west of In Amenas. This asset was in the exploration phase and was BP-operated. The Bourarhat agreement with Sonatrach expired on 23 September 2014. Sonatrach and BP were granted a six-month period to negotiate new terms and those negotiations commenced in the fourth quarter. With insufficient certainty of success, BP recorded an exploration write-off of $524 million.

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 2014 were $515 million ($38 million current and $477 million non-current).

BP served the National Oil Corporation with notices of force majeure on 17 August. This is the result of continued civil unrest in Libya, which has made it impossible for BP to undertake its obligations under the EPSA safely and securely. If the period of force majeure continues for two years, the EPSA may terminate if the parties have failed to reach an agreeable arrangement.

In Egypt, BP and its partners currently produce 10% of Egypt s liquids production and more than 30% of its gas production. BP s total assets in Egypt at 31 December 2014 were $7,715 million, of which $2,266 million were current and $5,449 million were non-current. The current assets include trade receivables and Egyptian pound denominated cash.

Egypt is moving forward towards the completion of the political roadmap set out in June 2013. The government is committed to completing the current transitional period and has already completed the first two milestones, the adoption of the Constitution by a majority vote earlier this year and the election of President Al Sisi in June. These are to be followed by Parliament elections scheduled to take place through two phases in March and April of 2015. Economic conditions remain

challenging despite the government s clear focus on triggering economic recovery and embarking on widescale national projects (such as the Suez Canal). Egypt is also holding an Economic Summit in March with the attendance of major foreign investors and with the government targeting significant investments in projects across the various sectors. Another key priority for the government is improving general security conditions and combating extremist elements in North Sinai.

- We achieved first gas from the DEKA project offshore Egypt in August with the start of production from the Denise South-6 well. The DEKA project is centred on the Denise and Karawan gas fields in the Temsah concession (BP 50%) in the East Nile.
- In September, we were awarded the El Matariya and Karawan concessions in Egyptian Natural Gas Holding Company s bid rounds through partnering (50%) with Dana Gas and ENI respectively. Karawan is located in the Mediterranean Sea in the northwestern part of Egypt s economic waters. El Mataria is an onshore block and BP is an operator. BP and its partners have committed to invest a total of $105 million in the blocks during the first phase.
- BP started drilling the Atoll-1 HPHT deepwater exploration well, the second exploration well in the North Damietta offshore concession, in September. Well performance is currently exceeding target pace and drilling operations are expected to be completed in second half of 2015.
- West Nile Delta Project Concessions amendment was approved by the Egyptian cabinet in December and will now proceed to the ratification process in 2015.

In Morocco, BP has 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 the Agadir Basin, offshore Morocco. The exploration periods run until 2017.

Asia

BP has activities in Western Indonesia, China, Azerbaijan, Oman, Abu Dhabi, India and Iraq.

In Western Indonesia, BP participates in LNG exports through our 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 14% of the total gas feed to Bontang, Indonesia s largest LNG export facility and one of the world s largest LNG plants. It has a capacity of 22 million tonnes of LNG per annum and output of more than 18 million tonnes.

In addition, BP participates in the Sanga-Sanga CBM PSA (BP 38%). Another CBM PSA, Tanjung IV (BP 44%), in the Barito basin of Central Kalimantan, will be relinquished pending the approval from the government of Indonesia.

In China, during the year BP has exited blocks 42/05 (BP 40.82%), 43/11 (BP 40.82%) and 54/11 (BP 100%) in the South China Sea in accordance with the PSAs and with government approvals. BP has a 30% equity stake in the 7 million tonnes per annum capacity Guangdong LNG regasification and pipeline project in south-east China, making it the first foreign partner in China s LNG import business. The terminal is supplied under a long-term contract with Australia s North West Shelf venture.

BP and the China National Offshore Oil Corporation (CNOOC) announced a heads of agreement in June for the supply of up to 1.5 million tonnes of LNG per year over 20 years starting in 2019.

In Azerbaijan, BP invests more than any other foreign investor, operates two PSAs, Azeri-Chirag-Gunashli (ACG) (BP 35.8%) and Shah Deniz (BP 28.83%), 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. The Shah Deniz Stage 2 project (referred to below) is also excluded from the EU and US sanctions. For further information see International trade sanctions on page 238.

The West Chirag platform came online in January, completing the Chirag oil project (BP 35.8%), sanctioned in 2010.

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- In March BP completed the purchase of an additional 3.33% equity in Shah Deniz and the South Caucasus Pipeline (SCP) from Statoil for $469 million.
- A ceremony to mark the groundbreaking for the Southern Gas Corridor was held in September as part of the BP-operated Azerbaijan International Operating Company celebration of the 20th anniversary of the Azeri-Chirag-Gunashli production-sharing contract. This is a milestone in the realization of the Shah Deniz Stage 2 project, which is planned to deliver gas through the Southern Corridor comprising some 3,500 kilometres of pipeline to customers in Georgia, Turkey, Greece, Bulgaria and Italy.
- In December BP and the State Oil Company of the Republic of Azerbaijan signed a new PSA to jointly explore for and develop potential prospects in the shallow water area around the Absheron Peninsula in the Azerbaijan sector of the Caspian Sea.

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 2014 of 712mboe/d.

BP is technical operator of, and currently holds a 28.83% interest in, the 693-kilometre SCP. The pipeline takes gas from Azerbaijan through Georgia to the Turkish border and has a capacity of 134mboe/d with average throughput in 2014 of 111mboe/d. BP (as operator of Azerbaijan International Operating Company) also operates the Western Export Route Pipeline which transports ACG oil to the Black Sea coast of Georgia.

In Oman, BP currently has appraisal programmes and development activities. In December 2013, BP and the Sultanate of Oman government signed a gas sales agreement and an amended EPSA for the development of the Khazzan field in block 61 with BP as operator.

- In February the Sultan of Oman issued a royal decree approving the amended EPSA and the government acquired a 40% stake in block 61 through Makarim Gas Development LLC, a wholly owned subsidiary of the state-owned Oman Oil Company Exploration & Production.

- In October we announced the award of two long-term drilling contracts for the Oman Khazzan project in block 61. KCA Deutag was awarded more than $400 million in contracts for the construction and operation of five new build land rigs for Khazzan. Oman s Abraj Energy Service was awarded more than $330 million in contracts to supply three drilling rigs for the full field development of the Khazzan project. Gas production is expected to start in late 2017.

In Abu Dhabi, we had equity interests of 9.5% and 14.67% in onshore and offshore concessions respectively in 2013. The Abu Dhabi onshore concession expired in January 2014 with a consequent impact on production of approximately 140mboe/d. BP participated in the tender process for the new onshore concession.

We also have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2014 supplied 5.9 million tonnes of LNG (305.7bcfe regasified).

In India, BP has a 30% interest in four oil and gas PSAs operated by Reliance Industries Limited (RIL), and is a partner with RIL in a 50:50 joint operation for the sourcing and marketing of gas in India.

During the year a number of activities continued to manage the existing producing fields in the KG D6 block, with a focus on sustaining production and extending the life of these fields. Activities included well work-overs, side-tracks and new wells as well as progress on the installation of additional compression capacity.
In October the government of India announced new gas price guidelines for domestic gas, effective 1 November 2014. The new guidelines replace the earlier guidelines issued by the government in January 2014.
During the year we recorded an $810-million charge (comprising a $415 million impairment charge and $395 million exploration write-off) to write down the value ascribed to block KG D6 in India as part of the acquisition of upstream interests from RIL in 2011. The charge arises as a result of uncertainty in the future long-term gas price outlook, following the introduction of a new formula for Indian gas prices, although we do see the commencement of a transition to market-based pricing as a positive step. We expect further clarity on the new pricing policy and the premiums for future developments to emerge in due course.

In Iraq, BP holds a 47.6% working interest and is the lead contractor in the Rumaila technical service contract. Rumaila is one of the world s largest oil fields, comprising five producing reservoirs. BP s total assets in Iraq at 31 December 2014 were $1,606 million ($1,235 million current and $371 million non-current).

In September we signed an amendment to the Rumaila contract terms, which include, among other things, the increase of BP equity and a five-year term extension until 2034. BP is also working with the government of Iraq and North Oil Company on studies in support of the stabilization and redevelopment of two producing reservoirs of the Kirkuk field. Despite instability and sectarian violence in the north and west of the country, BP operations are continuing in the south.

Australasia

We are active in Australia and Eastern Indonesia.

In Australia, BP is one of seven participants 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 of LNG per annum.

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 s Jansz-Io interest is in the reserves and wells which will provide the initial feed gas to the Gorgon LNG plant scheduled to commence production late 2015.

BP holds a 70% interest in four deepwater offshore exploration blocks in the Ceduna Sub Basin. 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 participants in the Browse LNG venture (operated by Woodside) and holds a 17% interest. Browse is currently in the pre-FEED stage of an offshore floating LNG development and remains subject to regulatory, joint operation and internal BP approvals.
We accessed new acreage in the offshore Outer Canning basin in Western Australia in September by farming in to two exploration permits (BP 21%).

In Eastern Indonesia, BP operates the Tangguh 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. It has a total capacity of 7.6 million tonnes of LNG per annum. Tangguh supplies LNG to customers in

Indonesia, China, South Korea, Mexico and Japan through a combination of long, medium and short-term contracts. Plans for a third train remain on track.

In August BP announced that the government of Indonesia, through the Ministry of Environment, approved the Tangguh expansion project integrated environment and social impact assessment and issued the project (BP 37.16%) an environmental permit. This was followed by the award of dual onshore FEED to two separate consortia, announced in October. In addition, BP and the Tangguh partners signed a long-term LNG sales agreement with PT PLN (Persero), Indonesia s state-owned electricity company, to supply up to 1.5 million tonnes of LNG each year from 2015 to 2033. Supply will initially be provided from Tangguh s existing LNG trains. The agreement commits 40% of annual production from train 3 to the domestic market.

BP has 100% interests in two deepwater PSAs: West Aru I and II and 32% interest in the Chevron-operated West Papua I and Ill PSAs. These PSAs will be relinquished pending approval from the government of Indonesia.

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Downstream plant capacity

The following table summarizes BP group s interests in refineries and average daily crude distillation capacities as at 31 December 2014.

Fuels value chain	Country	Refinery	Group interest[b] (%)	Crude distillation capacities[a] BP share thousand barrels per day
US				
US North West	US	Cherry Point	100	234
US East of Rockies		Whiting	100	430
		Toledo	50	80
				744
Europe				
Rhine	Germany	Bayernoil[c]	22.5	49
		Gelsenkirchen	50	132
		Karlsruhe[c]	12	39
		Lingen	100	95
		Schwedt[c]	18.8	45
	Netherlands	Rotterdam	100	377
Iberia	Spain	Castellón	100	110
				847
Rest of world				
Australia New Zealand	Australia	Bulwer[d]	100	102
		Kwinana	100	146
	New Zealand	Whangarei[c]	23.7	28
Southern Africa	South Africa	Durban[c]	50	90
				366
Total BP share of capacity at 31 December 2014				1,957

[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.

[d] We announced that we will halt refining operations at Bulwer in 2015.

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Petrochemicals production capacity[a]

The following table summarizes BP group s share of petrochemicals production capacities as at 31 December 2014.

			BP share of capacity thousand tonnes per annum[b]				
							Product
Geographical area	Site	Group interest (%)[c]	PTA	PX	Acetic acid	Olefins and derivatives	Others
US							
	Cooper River	100.0	1,300				
	Decatur[d]	100.0	1,000	700			
	Texas City	100.0		1,300	600[e]		100
			2,300	2,000	600		100
Europe							
UK	Hull	100.0			500		200
Belgium	Geel	100.0	1,300	700			
Germany	Gelsenkirchen[f]	50-61.0				1,800[g]	
	Mülheim[f]	50.0					100
			1,300	700	500	1,800	300
Rest of world							
Trinidad & Tobago	Point Lisas	36.9					700
China	Caojing	50.0				3,300	
	Chongqing	51.0			200		100
	Nanjing	50.0			300		
	Zhuhai[h]	85.0	1,800				
Indonesia	Merak	100.0	500				
South Korea	Ulsan	51.0			300		100
Malaysia	Kertih	70.0			400		
Taiwan	Kaohsiung	61.4	300				
	Mai Liao	50.0			200		
	Taichung	61.4	500				
			3,100		1,400	3,300	900
			6,700	2,700	2,500	5,100	1,300
Total BP share of capacity at 31 December 2014							18,300

[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] Capacities are shown to the nearest hundred thousand tonnes per annum.
[c] Includes BP share of equity-accounted entities, as indicated.
[d] This site has 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%.

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Oil and gas disclosures for the group

Resource progression

BP manages its hydrocarbon resources in three major categories: prospect inventory, contingent resources and 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 non-proved reserves or contingent resources.

Non-proved reserves and 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 volumes 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 2014 BP had material volumes of proved undeveloped reserves held for more than five years in Trinidad, the North Sea and the Gulf of Mexico. These are part of ongoing infrastructure-led 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 2014 we progressed 1,031mmboe of proved undeveloped reserves (483mmboe 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 $18,704 million in 2014 ($15,096 million for subsidiaries and $3,608 million for equity-accounted entities). The major areas with progressed volumes in 2014 were Angola, Azerbaijan, Russia, Trinidad, UK and 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 entities	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2014	8,080
Revisions of previous estimates	371
Improved recovery	196
Discoveries and extensions	146
Purchases	42
Sales	(15)
Total in year proved undeveloped reserves changes	8,819
Progressed to proved developed reserves	(1,031)
Proved undeveloped reserves at 31 December 2014	7,788

Subsidiaries only	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2014	4,844
Revisions of previous estimates	(183)
Improved recovery	180
Discoveries and extensions	123
Purchases	42
Sales	(15)
Total in year proved undeveloped reserves changes	4,990
Progressed to proved developed reserves	(483)
Proved undeveloped reserves at 31 December 2014	4,507

[a] Because of rounding, some totals may not agree exactly with the sum of their component parts.

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 cases BP uses numerical simulation as part of a holistic assessment of recovery factor for its fields, where these simulations 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. 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 10 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 and of the American Association of Petroleum Geologists Committee on Resource Evaluation and is the current chair of the bureau of the United Nations Economic Commission for Europe Expert Group on Resource Classification.

No specific portion of compensation bonuses for 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 2014, 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 2014. 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 its Annual Report on Form 20-F filed with the SEC.

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-four per cent of our total proved reserves of subsidiaries at 31 December 2014 were held through joint operations (83% in 2013), and 33% of the proved reserves were held through such joint operations where we were not the operator (31% in 2013).

Estimated net proved reserves of crude oil at 31 December 2014[a b c]

			million barrels
	Developed	Undeveloped	Total
UK	159	329	488
Rest of Europe	95	22	117
US	1,030	664	1,694
Rest of North America	9	163	172
South America	10	22	32
Africa	317	120	437
Rest of Asia	384	197	581
Australasia	40	19	59
Subsidiaries*	2,043	1,538	3,582
Equity-accounted entities	3,405	2,258	5,663
Total	5,448	3,796	9,244

Estimated net proved reserves of natural gas liquids at 31 December 2014[a b]

			million barrels
	Developed	Undeveloped	Total
UK	6	3	9
Rest of Europe	13	1	14
US	323	104	427
Rest of North America			
South America	11	28	39
Africa	5	7	12
Rest of Asia			
Australasia	6	3	10
Subsidiaries	364	146	510

Equity-accounted entities	46	16	62
Total	410	163	572

Estimated net proved reserves of liquids*

			million barrels
	Developed	Undeveloped	Total
Subsidiaries	2,407	1,684	4,092[d e]
Equity-accounted entities	3,451	2,274	5,725[f]
Total	5,858	3,958	9,817

Estimated net proved reserves of natural gas at 31 December 2014[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	382	386	768
Rest of Europe	300	19	318
US	7,168	2,447	9,615
Rest of North America	17		17
South America	2,352	6,313	8,666
Africa	901	1,597	2,497
Rest of Asia	1,688	3,892	5,580
Australasia	3,316	1,719	5,035
Subsidiaries	16,124	16,372	32,496[g]
Equity-accounted entities	6,363	5,837	12,200[h]
Total	22,487	22,209	44,695

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Estimated net proved reserves on an oil equivalent basis

	million barrels of oil equivalent		
	Developed	Undeveloped	Total
Subsidiaries	5,187	4,507	9,694
Equity-accounted entities	4,548	3,280	7,828
Total	9,735	7,788	17,523

[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 2014 marker prices used were Brent $101.27/bbl (2013 $108.02/bbl and 2012 $111.13/bbl) and Henry Hub $4.31/mmBtu (2013 $3.66/mmBtu and 2012 $2.75/mmBtu).

[c] Includes condensate and bitumen.

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 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 liquids in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[f] Includes 38 million barrels of crude oil in respect of the 0.16% non-controlling interest in Rosneft held assets in Russia.

[g] Includes 2,519 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[h] Includes 91 billion cubic feet of natural gas in respect of the 0.18% non-controlling interest in Rosneft held assets in Russia.

Because of rounding, some totals may not agree exactly with the sum of their component parts.

Proved reserves replacement

Total hydrocarbon proved reserves at 31 December 2014, on an oil equivalent basis including equity-accounted entities, decreased by 3% (decrease of 5% for subsidiaries and increase of 1% for equity-accounted entities) compared with 31 December 2013. Natural gas represented about 44% (58% for subsidiaries and 27% for equity-accounted entities) of these reserves. The change includes a net decrease from acquisitions and disposals of 39mmboe (all within our subsidiaries). Acquisition activity in our subsidiaries occurred in Azerbaijan, the US and the UK, and divestment activity in our subsidiaries in the US and Brazil.

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 2014, the proved reserves replacement ratio excluding acquisitions and disposals was 63% (129% in 2013 and 77% in 2012) for subsidiaries and equity-accounted entities, 29% for subsidiaries alone and 116% for equity-accounted entities alone. The decreased ratio reflected lower reserves bookings as a result of fewer final investment decisions in 2014 and revisions of previous estimates.

In 2014 net additions to the group s proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 743mmboe (208mmboe for subsidiaries and 535mmboe 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 2014 principally resulted from the application of conventional technologies. The principal proved reserves additions in our subsidiaries were in Angola, Azerbaijan, Iraq, Oman, Trinidad and the US. We had material reductions in our proved reserves in Norway, the UK, Indonesia and Australia, principally due to activity reduction and reservoir performance. The principal reserves additions in our equity-accounted entities were in Argentina and Russia.

Sixteen per cent of our proved reserves are associated with PSAs. The countries in which we operated under PSAs in 2014 were Algeria, Angola, Azerbaijan, Egypt, India, Indonesia, Oman and a non-material volume of our proved reserves 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. Our Abu Dhabi offshore concession is due to expire in 2018. 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 174.

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BP s net production by country crude oil[a] and natural gas liquids

						thousand barrels per day
						BP net share of production[b]
			Crude oil			Natural gas liquids
	2014	2013	2012	**2014**	2013	2012
Subsidiaries	**46**	58	81			
UK[c,d]				**2**	3	5
Norway[c]	**41**	31	22	**5**	4	1
Total Rest of Europe	**41**	31	22	**5**	4	1
Total Europe	**87**	89	103	**7**	7	6
Alaska[c]	**127**	137	139			
Lower 48 onshore[c]	**14**	12	11	**45**	45	49
Gulf of Mexico deepwater[c]	**206**	156	176	**18**	13	15
Total US	**347**	305	327	**63**	58	64
Canada[c]						1
Total Rest of North America						1
Total North America	**347**	305	327	**63**	58	65
Trinidad & Tobago	**13**	10	8	**12**	12	13
Brazil[c]		7	7			
Total South America	**13**	17	16	**12**	12	13
Angola	**181**	180	149			
Egypt	**37**	33	36			
Algeria	**5**	3	6	**5**	3	7
Total Africa	**222**	217	191	**5**	3	7
Azerbaijan[c]	**98**	96	92			
Western Indonesia	**2**	1	1			
Iraq	**55**	39	39			
Other	**2**	4	6		1	2
Total Rest of Asia	**156**	141	137		1	2
Total Asia	**156**	141	137		1	2
Australia	**17**	19	20	**3**	4	4
Other	**2**	2	1			
Total Australasia	**19**	21	22	**3**	4	4
Total subsidiaries[e]	**844**	789	795	**91**	86	96
Equity-accounted entities (BP share)						
TNK-BP (Russia, Venezuela, Vietnam)[c,f]		183	857		4	20
Rosneft (Russia, Canada, Venezuela, Vietnam)[c,g]	**816**	643		**5**	7	
Abu Dhabi[h]	**97**	231	216			
Argentina	**62**	60	63	**3**	3	3
Bolivia	**3**	2	1			
Egypt				**4**	5	5
Other	**1**	1	1			

Total equity-accounted entities	**979**	1,120	1,137	**12**	19	27
Total subsidiaries and equity-accounted entities	**1,823**	1,909	1,932	**104**	105	123

[a] Includes condensate.

[b] 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.

[c] In 2014, BP divested its interests in the Endicott and Northstar fields, and 50% of its interests in the Milne Point field, in Alaska, its interest in the US onshore Hugoton upstream operation and its interest in the Polvo asset in Brazil. BP also reduced its interest in certain wells in the US onshore Eagle Ford Shale in south Texas. It increased its interest in the Shah Deniz asset in Azerbaijan, in certain UK North Sea assets, and in certain US onshore assets. 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.

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

[e] Includes 7 net mboe/d of NGLs from processing plants in which BP has an interest (2013 5.5mboe/d and 2012 13.5mboe/d).

[f] 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.

[g] 2014 is based on preliminary operational results of Rosneft for the three months ended 31 December 2014. Actual results may differ from these amounts. 2013 reflects production for the period 21 March to 31 December, averaged over the full year.

[h] BP holds interests, through associates, in offshore concessions in Abu Dhabi which expire in 2018. We similarly held onshore concessions which expired in 2014.

Because of rounding, some totals may not agree exactly with the sum of their component parts.

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BP s net production by country natural gas

	million cubic feet per day BP net share of production[a] 2014	2013	2012
Subsidiaries			
UK[b]	**71**	157	414
Norway	**102**	80	8
Total Rest of Europe	**102**	80	8
Total Europe	**173**	237	422
Lower 48 onshore[b]	**1,350**	1,404	1,499
Gulf of Mexico deepwater[b]	**159**	114	134
Alaska	**11**	21	18
Total US	**1,519**	1,539	1,651
Canada	**10**	11	13
Total Rest of North America	**10**	11	13
Total North America	**1,529**	1,551	1,664
Trinidad & Tobago	**2,147**	2,221	2,097
Total South America	**2,147**	2,221	2,097
Egypt	**406**	444	470
Algeria	**107**	117	120
Total Africa	**513**	561	590
Azerbaijan[b]	**230**	203	158
Western Indonesia	**47**	51	59
India	**131**	156	313
Other[b]		81	103
Total Rest of Asia	**408**	490	633
Total Asia	**408**	490	633
Australia	**450**	431	435
Eastern Indonesia	**364**	353	352
Total Australasia	**814**	784	787
Total subsidiaries[c]	**5,585**	5,845	6,193
Equity-accounted entities (BP share)			
TNK-BP (Russia, Venezuela, Vietnam)[b d]		184	785
Rosneft (Russia, Canada, Venezuela, Vietnam)[b e]	**1,084**	617	
Argentina	**323**	329	355
Bolivia	**80**	55	34
Other	**28**	30	26
Total equity-accounted entities[c]	**1,515**	1,216	1,200
Total subsidiaries and equity-accounted entities	**7,100**	7,060	7,393

[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 2014, BP divested its interest in the US onshore Hugoton upstream operation. BP also reduced its interest in certain wells in the US onshore Eagle Ford Shale in south Texas. It increased its interest in the Shah Deniz asset in Azerbaijan, in certain UK North Sea assets, and in certain US onshore assets. 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.

[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] 2014 is based on preliminary operational results of Rosneft for the three months ended 31 December 2014. Actual results may differ from these amounts. 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.

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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										
2014										
Crude oil[c]	**96.02**	**97.77**	**93.66**		**96.85**	**93.99**		**91.05**	**94.04**	**93.65**
Natural gas liquids	**58.11**	**52.97**	**32.28**		**41.62**	**53.67**			**65.70**	**36.15**
Gas	**8.13**	**8.22**	**3.80**		**4.65**	**5.92**		**6.28**	**11.20**	**5.70**
2013										
Crude oil[c]	107.83	107.78	102.07		106.37	107.02		108.26	105.89	105.38
Natural gas liquids	62.53	61.82	30.95		54.92	69.39			68.13	38.38
Gas	9.43	10.18	3.07		4.66	5.75		4.99	10.55	5.35
2012										
Crude oil[c]	111.76	109.07	107.55		105.83	110.08		109.74	106.47	108.94
Natural gas liquids	74.38	60.36	34.65		52.46	75.82			84.96	42.75
Gas	8.62	9.43	2.32		3.53	6.05		5.08	10.08	4.75
Equity-accounted entities[d]										
2014										
Crude oil[c]					**73.87**		**84.19**	**14.70**		**72.53**
Natural gas liquids					**15.75**		**n/a**			**15.75**
Gas					**4.73**		**2.18**	**12.83**		**3.01**
2013										
Crude oil[c]					74.01		95.28	11.58		63.51
Natural gas liquids					29.63		n/a			29.63
Gas					4.05		2.47	13.21		3.26
2012										
Crude oil[c]					81.32		86.76	10.15		62.11
Natural gas liquids					22.36		7.63			9.70
Gas					2.35		2.35	5.08		2.52

[a] Units of production are barrels for liquids and thousands of cubic feet for gas. Realizations include transfers between businesses, except in the case of Russia in 2014 and 2013.

[b] Amounts reported for Russia in 2014 and 2013 include BP s share of Rosneft s worldwide activities, including insignificant amounts outside Russia. The operational and financial information of the Rosneft segment for 2014 is based on preliminary operational and financial results of Rosneft for the three months ended 31 December 2014. Actual results may differ from these amounts. Crude oil includes natural gas liquids in 2014 and 2013.

[c] Includes condensate.

[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										
2014	**44.67**	**18.85**	**14.22**		**5.43**	**13.37**		**15.55**	**3.92**	**12.68**
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
Equity-accounted entities										
2014					**11.28**		**3.82**	**4.34**		**4.75**
2013					12.16		4.36	4.19		5.28
2012					11.33		5.72	2.88		5.76

[a] Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

[b] Amounts reported for Russia in 2014 and 2013 include BP s share of Rosneft s worldwide activities, including insignificant amounts outside Russia. The operational and financial information of the Rosneft segment for 2014 is based on preliminary operational and financial results of Rosneft for the three months ended 31 December 2014. Actual results may differ from these amounts.

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Environmental expenditure

			$ million
	2014	2013	2012
Environmental expenditure relating to the Gulf of Mexico oil spill	**190**	(66)[a]	919
Operating expenditure	**624**	657	742
Capital expenditure	**590**	1,091	1,207
Clean-ups	**33**	42	47
Additions to environmental remediation provision	**371**	472	549
Additions to decommissioning provision	**2,216**	2,092	3,766

[a] The environmental expenditure credit of $66 million in 2013 arises primarily from the write-back of a spill response provision.

Environmental expenditure relating to the Gulf of Mexico oil spill

For full details of all environmental activities in relation to the Gulf of Mexico oil spill, see Financial statements Note 2.

Other environmental expenditure

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

Environmental operating expenditure of $624 million in 2014 was at a similar level to 2013.

Capital expenditure in 2014 was lower than in 2013 principally due to reduced levels of construction activity at our Whiting refinery in 2014 as compared to 2013. The final major units associated with the Whiting refinery modernization project were commissioned in December 2013.

Clean-up costs in 2014 were lower than in 2013 primarily due to an overall reduction in clean-up activities and services required across sites.

In addition to operating and capital expenditures, we also establish provisions for future environmental remediation. Expenditure against such provisions normally occurs in subsequent periods and is not included in environmental operating expenditure reported for such periods.

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

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

Additions to our environmental remediation provision decreased in 2014 largely due to scope reassessments of the remediation plans of a number of our sites in the US and Canada. The charge for environmental remediation provisions in 2014 included $13 million in respect of provisions for new sites (2013 $13 million and 2012 $19 million).

In addition, we make provisions on installation of our oil- and gas-producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility, a provision is established that represents the discounted value of the expected future cost of decommissioning the asset.

In 2014 additions to the decommissioning provision were greater than in 2013, and occurred as a result of detailed reviews of expected future costs, and to a lesser extent increases to the asset base. The majority of these additions related to our sites in the North Sea, the Gulf of Mexico and Angola. The additions in 2012 and 2013 were driven by changes in estimation and detailed reviews of expected future costs.

In 2012 and 2013, the Gulf of Mexico was impacted by the Bureau of Ocean Energy Management, Regulation and Enforcement s (BOEMRE) Notice to Lessees (NTL) 2010-G05, issued in October 2010, which requires that idle infrastructure on active leases be decommissioned earlier than previously was required and establishes guidelines to determine the future utility of idle infrastructure on active leases.

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

Provisions for environmental remediation and decommissioning are usually established on a discounted basis, as required by IAS 37 Provisions, Contingent Liabilities and Contingent Assets . Further details of decommissioning and environmental provisions appear in the financial statements Note 21.

Regulation of the group s business

BP s activities, including its oil and gas exploration and production, pipelines and transportation, refining and marketing, petrochemicals production, trading, biofuels, wind and shipping activities, are conducted in almost 80 countries and are subject to a broad range of EU, US, international, regional and local legislation and regulations, including legislation that implements international conventions and protocols. These cover virtually all aspects of BP s activities and include matters such as licence acquisition, production rates, royalties, environmental, health and safety protection, fuel specifications and transportation, trading, pricing, anti-trust, export, taxes and foreign exchange.

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

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

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

In certain countries, separate licences are required for exploration and production activities, and in some cases production licences are limited to only a portion of the area covered by the original exploration licence. Both exploration and production licences are generally for a specified period of time. In the US, leases from the US government typically remain in effect for a specified term, but may be extended beyond that term as long as there is production in paying quantities. The term of BP s licences and the extent to which these licences may be renewed vary from country to country.

BP frequently conducts its exploration and production activities in joint arrangements* or co-ownership arrangements with other international oil companies, state-owned or controlled companies and/or private companies. These joint arrangements may be incorporated or unincorporated arrangements, while the co-ownerships are typically unincorporated. Whether incorporated or unincorporated, relevant agreements set out each party s level of participation or ownership interest in the joint arrangement or co-ownership. Conventionally, all costs, benefits, rights, obligations, liabilities and risks incurred in carrying out joint-arrangement or co-ownership operations under a lease or licence are shared among the joint-arrangement or co-owning parties according to these agreed ownership interests. Ownership of joint-arrangement or co-owned property and hydrocarbons to which the joint arrangement or co-ownership is entitled is also shared in these proportions. To the extent that any liabilities arise, whether to governments or third parties, or as between the joint arrangement parties or co-owners themselves, each joint arrangement party or co-owner will generally be liable to meet these in proportion to its ownership interest. In many upstream operations, a party (known as the operator) will be appointed (pursuant to a joint operating agreement) to carry out day-to-day operations on behalf of the joint arrangement or co-ownership. The operator is typically one of the joint arrangement parties or a co-owner and will carry out its duties either through its own staff, or by contracting out various elements to third-party contractors or service providers. BP acts as operator on behalf of joint arrangements and co-ownerships in a number of countries where it has exploration and production activities.

Frequently, work (including drilling and related activities) will be contracted out to third-party service providers who have the relevant expertise and equipment not available within the joint arrangement or the co-owning operator s organization. The relevant contract will specify the work to be done and the remuneration to be paid and will typically set out how major risks will be allocated between the joint arrangement or co-ownership and the service provider. Generally, the joint arrangement or co-owner and the contractor would respectively allocate responsibility for and provide reciprocal indemnities to each other for harm caused to their respective staff and property. Depending on the service to be provided, an oil and gas industry service contract may also contain provisions allocating risks and liabilities associated with pollution and environmental damage, damage to a well or hydrocarbon reservoir and for claims from third parties or other losses. The allocation of those risks vary among contracts and are determined through negotiation between the parties.

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

Environmental regulation

Current and proposed fuel and product specifications, emission controls, climate change programmes and regulation of unconventional oil and gas extraction under a number of environmental laws may have a significant effect on the production, sale and profitability of many of BP s products.

There are also environmental laws that require BP to remediate and restore areas affected by the release of hazardous substances or hydrocarbons associated with our operations. These laws may apply to sites that BP currently owns or operates, sites that it previously owned or operated, or sites used for the disposal of its and other parties waste. See Financial Statements Note 21 for information on provisions for environmental restoration and remediation.

A number of pending or anticipated governmental proceedings against certain BP group companies under environmental laws could result in monetary or other sanctions. Group companies are also subject to environmental claims for personal injury and property damage alleging the release of, or exposure to, hazardous substances. The costs associated with future environmental remediation obligations, governmental proceedings and claims could be significant and may be material to the results of operations in the period in which they are recognized. We cannot accurately predict the effects of future developments, such as stricter environmental laws or enforcement policies, or future events at our facilities, on the group, and there can be no assurance that material liabilities and costs will not be incurred in the future. For a discussion of the group s environmental expenditure see page 225.

A significant proportion of our fixed assets are located in the US and the EU. US and EU environmental, health and safety regulations significantly affect BP s operations. Significant legislation and regulation in the US and the EU affecting our businesses and profitability includes the following:

United States

- The Clean Air Act (CAA) regulates air emissions, permitting, fuel specifications and other aspects of our production, distribution and marketing activities. Stricter limits on sulphur in fuels will affect us in future, as will actions on greenhouse gas (GHG) emissions and other air pollutants. States may also have separate, stricter air emission laws in addition to the CAA.
- The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 affect our US fuel markets by, among other things, imposing renewable fuel mandates and imposing GHG emissions thresholds for certain renewable fuels. States such as California also impose additional fuel carbon standards.
- The Clean Water Act regulates wastewater and other effluent discharges from BP s facilities, and BP is required to obtain discharge permits, install control equipment and implement operational controls and preventative measures.
- The Resource Conservation and Recovery Act regulates the generation, storage, transportation and disposal of wastes associated with our operations and can require corrective action at locations where such wastes have been disposed of or released.
- The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) can, in certain circumstances, impose the entire cost of investigation and remediation on a party who owned or operated a site contaminated with a hazardous substance, or arranged for disposal of a hazardous substance at a site. BP has incurred, or is likely to incur, liability under the CERCLA or similar state laws, including costs attributed to insolvent or unidentified parties. BP is also subject to claims for remediation costs under other federal and state laws, and to claims for natural resource damages under the CERCLA, the Oil Pollution Act of 1990 (OPA 90) (discussed below) and other federal and state laws. CERCLA also requires hazardous substance release notification.
- The Toxic Substances Control Act regulates BP s manufacture, import, export, sale and use of chemical substances and products.
- The Occupational Safety and Health Act imposes workplace safety and health requirements on BP operations along with significant process safety management obligations.
- In May 2012, the US adopted the UN Global Harmonization System (GHS) for hazard classification and labelling of chemicals and products, with the modification of the Occupational Safety & Health Administration (OSHA) Hazard Communication Standard. This requires BP to reassess the hazards of all our chemicals and products against new GHS criteria as adopted or modified by OSHA and to update warning labels and safety data sheets accordingly by 1 June 2015.
- The US Department of Transportation (DOT) regulates the transport of BP s petroleum products such as crude oil, gasoline, petrochemicals and other hydrocarbon liquids.
- The Maritime Transportation Security Act (MTSA), the DOT Hazardous Materials (HAZMAT) and the Chemical Facility Anti-Terrorism Standard (CFATS) regulations impose security compliance regulations on around 30 BP facilities.
- OPA 90 is implemented through regulations issued by the US Environmental Protection Agency (EPA), the US Coast Guard, the DOT, OSHA, the Bureau of Safety and Environmental Enforcement and various states. Alaska and the West Coast states currently have the most demanding state requirements.

As a consequence of the Deepwater Horizon incident, BP has become subject to claims under OPA 90 and other laws and has established a $20-billion trust fund for legitimate state and local government response claims, final judgments and settlement claims, legitimate state and local response costs, natural resource damages and related costs and legitimate individual and business claims (see Gulf of Mexico oil spill on page 36). BP is also subject to natural resource damages claims, claims for civil penalties under the Clean Water Act, and numerous civil lawsuits by individuals, businesses and governmental entities. The ultimate costs for these claims cannot be determined at this time. For further disclosures relating to the 2010 Deepwater Horizon oil spill, see Legal proceedings on page 228.

BP has also been in discussions with the EPA regarding alleged CAA violations at the Toledo refinery and the EPA has alleged certain CAA violations at the Cherry Point refinery and the Carson refinery which BP sold to Tesoro Corporation on 1 June 2013.

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European Union

In October 2014, the European Council agreed on new climate and energy targets for the period up to 2030.
The 2008 EU Climate and Energy Package is expected to remain in place until 2020 and includes an updated EU Emissions Trading System (EU ETS) Directive and the Renewable Energy Directive. The updated EU ETS has been expanded to include, among others, the petrochemical sector. Installations in sectors at risk of carbon leakage (i.e. production transfers out of the EU ETS trading area) are partially compensated with free allocation of emission allowances based on sector benchmarks used to calculate the number of free emissions per installation.
The Energy Efficiency Directive (EED) was adopted in 2012. It requires EU Member States to implement an indicative 2020 energy saving target and apply a framework of measures as part of a national energy efficiency programme, including mandatory industrial energy efficiency surveys. This directive is being implemented in the UK by the Energy Savings Opportunity Scheme (ESOS), which affects our offshore and onshore assets. ISO50001 is being implemented in some EU states to meet some elements of the Energy Efficiency Directive.
The Industrial Emissions Directive (IED) provides the framework for granting permits for major industrial sites. It lays down rules on integrated prevention and control of air, water and soil pollution arising from industrial activities. This may result in requirements for BP to further reduce its emissions, particularly its air and water emissions. As part of the IED framework, additional emission limit values are informed by the sector specific and cross-sector Best Available Technology (BAT) Conclusions, such as the recently published BAT Conclusions for the refining sector. Further BAT Conclusions that may result in additional emission reduction requirements are expected within the next two years.
The European Commission s Clean Air Policy Package (including a new directive for medium-sized combustion plants, a revised National Emission Ceilings Directive and a ratification proposal for the amended Gothenburg Protocol) may once adopted wholly or in part result in requirements for further emission reductions at BP s EU sites.
The implementation of the Water Framework Directive and the Environmental Quality Directive may mean that BP has to take further steps to manage freshwater withdrawals and discharges from its EU operations.
The EU regulation on ozone depleting substances (ODS) requires BP to reduce the use of ODS and phase out use of certain ODSs. BP continues to replace ODS in refrigerants and/or equipment, in the EU and elsewhere, in accordance with the Montreal Protocol and related legislation. In addition, the EU regulation on fluorinated gases with high global warming potential came into force on 1 January 2015. This might further limit the use of some refrigerants, such as in gas processing facilities.
The EU Fuel Quality Directive affects our production and marketing of transport fuels. Revisions adopted in 2009 mandate reductions in the life cycle GHG emissions per unit of energy and tighter environmental fuel quality standards for petrol and diesel.
The EU Registration, Evaluation and Authorization of Chemicals (REACH) Regulation requires registration of chemical substances manufactured in or imported into the EU, together with the submission of relevant hazard and risk data. REACH affects our refining, petrochemicals, exploration and production, biofuels, lubricants and other manufacturing or trading/import operations. In accordance with the required phase-in timetable, BP has completed registration of all substances in tonnage bands equal to or greater than 100 tonnes per annum/legal entity, and is in the process of preparing registration dossiers for substances manufactured or imported in amounts in the range 1-100 tonnes per annum/legal entity that are currently due to be submitted before 31 May 2018. Some substances registered previously, including substances supplied to us by third parties for our use, are now subject to thorough evaluation and review for potential authorization and restriction procedures, and possible banning, by the European Chemicals Agency and EU member state authorities.
In addition, the EU is implementing the UN Global Harmonization System for hazard classification and labelling of chemicals and products through the Classification Labelling and Packaging (CLP) Regulation. This requires BP to

reassess the hazards of all our chemicals and products against the new GHS criteria as adopted or modified by the EU and to update warning labels and safety data sheets accordingly. The CLP will come into effect for mixtures (e.g. lubricants) in 2015. A separate EU regulation on export and import of hazardous chemicals requires warning labels and safety data sheets accompanying EU exports to be compliant with relevant CLP and REACH requirements (unless this conflicts with requirements in the importing country) and, as far as practicable, in the official or one or more principal languages of the intended area of use. Safety data sheets for the EU market have been or are being updated to include both REACH and CLP information.

The EU Offshore Safety Directive, adopted in 2013, is required to be transposed into national legislation by Member States, including the UK, by 19 July 2015. Its purpose is to introduce a harmonized regime aimed at reducing the potential environmental, health and safety impacts of the offshore oil and gas industry throughout EU waters. Implementation into UK legislation will involve alignment of the regime currently operating in the UK.

Environmental maritime regulations

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

In US waters, OPA 90 imposes liability and spill prevention and planning requirements governing, among others, tankers, barges and offshore facilities. It also mandates a levy on imported and domestically produced oil to fund oil spill responses. Some states, including Alaska, Washington, Oregon and California, impose additional liability for oil spills. Outside US territorial waters, BP shipping tankers are subject to international liability, spill response and preparedness regulations under the UN s International Maritime Organization, including the International Convention on Civil Liability for Oil Pollution, the International Convention for the Prevention of Pollution from Ships (MARPOL) Convention, the International Convention on Oil Pollution, Preparedness, Response and Co-operation and the International Convention on Civil Liability for Bunker Oil Pollution Damage. In April 2010, the Hazardous and Noxious Substance (HNS) Protocol 2010 was adopted to address issues that have inhibited ratification of the International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea 1996. As of 6 January 2015, the number of contracting states to the HNS Convention remained at 14, so it has not yet entered into force.

Changes to the permitted level of sulphur in marine fuels under EU mandated reductions and International Maritime Organization guidelines over the next 5-10 years are intended to result in the reduction of sulphur oxides emissions from ships, either through the burning of low sulphur marine fuels or the use of approved on-board abatement technology. These restrictions are expected to place additional costs on refineries producing marine fuel, including costs to dispose of sulphur, as well as increased GHG emissions and energy costs for additional refining.

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

Greenhouse gas regulation

Increasing concerns about climate change have led to a number of international climate agreements and negotiations that are ongoing.

In 2011, parties to the UN Framework Convention on Climate Change conference in Durban (COP17) agreed to several measures. One was a roadmap for negotiating a legal framework for action on climate change by 2015 that would involve all countries by 2020 and would close the ambition gap between existing GHG reduction pledges and what is required to achieve the goal of limiting global temperature rise to 2°C. Another was a second commitment period for the Kyoto Protocol to begin immediately after the first period. An amendment was subsequently adopted at the 2012 conference of parties (COP18) in Doha establishing a second commitment period to run until the end of 2020. However, it will not include the US, Canada, Japan and Russia and thus covers only about 15% of global emissions.

The 2014 conference (COP20) in Lima adopted the Lima Call for Climate Action. This included the elements of a negotiating text for a new international agreement, as specified in Durban in 2011, to be finalized at COP21 in Paris in December 2015. This text covers long-term ambitions and pathways and a framework for reaching it. COP20 also agreed on the rules for providing and assessing information about each country s Intended Nationally Determined Contributions (INDCs) towards reaching the overall ambition. The world s three largest emitters China, the US and the EU have all announced their intentions to limit their GHG emissions.

Additional, more stringent, measures can be expected in the future. These measures could increase BP s production costs for certain products, increase demand for competing energy alternatives or products with lower-carbon intensity, and affect the sales and specifications of many of BP s products. Current and announced measures and developments potentially affecting BP s businesses include the following:

- The EU has agreed to an overall GHG reduction target of 20% by 2020. To meet this, a Climate and Energy Package of regulatory measures has been adopted that includes: a collective national reduction target for emissions not covered by the EU ETS; binding national renewable energy targets to double usage of renewable energy sources in the EU including at least a 10% share of renewable energy in the transport sector; a legal framework to promote carbon capture and storage (CCS); and a revised EU ETS Phase 3. EU ETS revisions include a GHG reduction of 21% from 2005 levels; a significant increase in allowance auctioning; an expansion in the scope of the EU ETS to encompass more industrial sectors and gases and no free allocation for electricity generation or production but benchmarked free allocation for energy-intensive and trade-exposed industrial sectors. EU energy efficiency policy is currently implemented via national energy efficiency action plans and the Energy Efficiency Directive adopted in 2012. The EU has also recently agreed to the framework of the 2030 Climate and Energy Policies with a goal of at least a 40% reduction in GHGs from 1990 and measures to achieve a 27% share of renewable energy and a 27% increase in energy efficiency. The GHG reduction target is to be achieved by a 43% reduction of emissions from sectors covered by the EU ETS, and a 30% GHG reduction by Member States for all other GHG emissions.
- New Zealand s emission trading scheme (NZ ETS) commenced on 1 July 2010 for transport fuels, industrial processes and stationary energy. New Zealand also employs a portfolio of mandatory and voluntary complementary measures aimed at GHG reductions.
- Canada s highest emitting province, Alberta, has regulations targeting large final emitters (sites with over 100,000 tonnes CO2e/per annum) with intensity targets of 2% improvement per year up to 12%. Compliance is possible via direct reductions, the purchase of offsets or the payment of C$15/tonne to a technology fund.
- In the US, the US Environmental Protection Agency (EPA) continues to pursue regulatory measures to address GHGs under the Clean Air Act (CAA).
  - EPA regulations impose light duty vehicle emissions standards for GHGs and permitting requirements for certain large GHG emission sources.
  - Under the GHG mandatory reporting rule (GHGMRR), annual reports on GHG emissions must be filed. In addition to direct emissions from affected facilities, producers and importers/exporters of petroleum products, certain natural gas liquids and GHGs are required to report product volumes and notional GHG emissions as if these products were fully combusted.
  - The EPA proposed regulations establishing GHG emission limits for new and modified power plants in September 2013. In June 2014, the EPA proposed a very complex Clean Energy Plan Regulation that establishes

GHG reduction requirements, at a state or regional level, for existing power plants. The EPA announced its intention to finalize both rules in or around June 2015. These rules are important due to potential impacts on electricity prices, reliability of electricity supply, precedents for similar rules targeting other sectors and potential impacts on combined heat and power installations.

A number of additional state and regional initiatives in the US will affect our operations. California implemented a low-carbon fuel standard in 2010. The California cap and trade programme started in January 2012 with the first auctions of carbon allowances held in November 2012 and obligations commencing from 2013. The California cap and trade programme was broadened to include transport fuels on 1 January 2015.

In the recent US-China joint announcement on climate change addressing post-2020 actions, the US committed to reducing its GHG emissions by 26-28% below its 2005 level by 2025. Achieving these reductions will require expanded efforts to reduce emissions, which likely will include regulatory measures. China announced it intends to achieve a peak in CO2 emissions around 2030, with the intention to try to peak earlier and to increase the non-fossil fuel share of all energy to around 20% by 2030. Currently, China has targets to reduce carbon intensity of GDP 40-45% below 2005 levels by 2020 and increase the share of non-fossil fuels in total energy consumption from 7.5% in 2005 to 15% by 2020.

China is operating emission trading pilots in five cities and two provinces. A number of BP joint venture* companies in China are participating in these schemes. The Chinese government is also considering a plan for a national cap and trade system in 2016.

South Africa has delayed implementation of a carbon tax on carbon intensive emitters until 2016.

South Korea commenced its carbon emissions trading scheme in January 2015.

For information on the steps that BP is taking in relation to climate change issues and for details of BP s GHG reporting see Environment and society on page 42.

Legal proceedings

Proceedings relating to the Deepwater Horizon oil spill

BP s potential liabilities resulting from threatened, pending and potential future claims, lawsuits and enforcement actions relating to the 20 April 2010 explosions and fire on the semi-submersible rig Deepwater Horizon and resulting oil spill (the Incident), together with the potential cost of implementing remedies sought in the various proceedings, cannot be fully estimated at this time, but they have had and 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 potential liabilities may continue to have a material adverse effect on the group s results and financial condition. See Financial statements Note 2 for information regarding the financial impact of the Incident.

BP p.l.c., BP Exploration & Production Inc. (BPXP) and various other BP entities (collectively referred to as BP) are among the companies named as defendants in approximately 3,000 pending civil lawsuits relating to the Incident and further actions are likely to be brought. BPXP was lease operator of Mississippi Canyon, Block 252 in the Gulf of Mexico (Macondo), where the Deepwater Horizon was deployed at the time of the Incident. The other working interest owners at the time of the Incident were Anadarko Petroleum Company (Anadarko) and MOEX Offshore 2007

LLC (MOEX). The Deepwater Horizon, which was owned and operated by certain affiliates of Transocean Ltd. (Transocean), sank on 22 April 2010. The pending lawsuits and/or claims arising from the Incident have generally been brought in US federal and state courts. The plaintiffs include individuals, corporations, insurers and governmental entities and many of the lawsuits purport to be class actions. The lawsuits assert, among others, claims under the Oil Pollution Act of 1990 (OPA 90), claims for personal injury in connection with the Incident itself and the response to it, wrongful death, commercial and economic injury, breach of contract and violations of statutes. Many of the lawsuits assert claims which are excluded from the Economic and Property Damages Settlement Agreement (discussed below), including claims for recovery for losses allegedly resulting from the 2010 federal deepwater drilling moratoria and/or the related permitting process. The lawsuits seek various remedies including compensation to injured workers, recovery for commercial losses and property damage, compensation for personal injuries and medical monitoring, claims for environmental damage,

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remediation costs, claims for unpaid wages, injunctive and declaratory relief, treble damages and punitive damages. Purported classes of claimants include residents of the states of Louisiana, Mississippi, Alabama, Florida and Texas; property owners and rental agents, fishermen and persons dependent on the fishing industry, charter boat owners and deck hands, marina owners, gasoline distributors, shipping interests, restaurant and hotel owners, cruise lines and others who are property and/or business owners alleged to have suffered economic loss; and response workers and residents claiming injuries due to exposure to the components of oil and/or chemical dispersants. Among other claims arising from the spill response efforts, lawsuits have been filed claiming that additional payments are due by BP under certain Master Vessel Charter Agreements entered into in the course of the Vessels of Opportunity Program implemented as part of the response to the Incident. Purported class action and individual lawsuits have also been filed in US state and federal courts, as well as one suit in Canada, against BP entities and/or various current and former officers and directors alleging, among other things, shareholder derivative claims, securities fraud claims, violations of the Employee Retirement Income Security Act (ERISA) and contractual and quasi-contractual claims related to the cancellation of the dividend on 16 June 2010.

Many of the lawsuits pending in federal court have been consolidated by the Federal Judicial Panel on Multidistrict Litigation into two multi-district litigation proceedings, one in federal district court in Houston for the securities, derivative and ERISA cases (MDL 2185) and another in federal district court in New Orleans for the remaining cases (MDL 2179).

MDL 2179 and related matters

DoJ Action; liability limitation-, contribution- and indemnity-related proceedings; and Trial of Liability, Limitation, Exoneration and Fault Allocation

On 13 May 2010, Transocean and certain affiliates filed a complaint under admiralty law in federal court in Texas seeking exoneration from or limitation of liability as managing owners and operators of the Deepwater Horizon. That action (the Limitation Action) was consolidated with MDL 2179 on 24 August 2010.

The US filed a civil complaint in MDL 2179 against BPXP and others on 15 December 2010 (the DoJ Action). The complaint seeks an order finding liability under OPA 90 and civil penalties under the Clean Water Act and sets forth a purported reservation of rights on behalf of the US to amend the complaint or file additional complaints seeking various remedies under various US federal laws and statutes.

On 18 February 2011, Transocean filed a third-party complaint against BP, the US government, and other corporations involved in the Incident, naming those entities as formal parties in the Limitation Action. On 20 April 2011, Transocean filed claims in the Limitation Action alleging that BP had breached BP America Production Company s (BPAPC) contract with Transocean Holdings LLC by BP not agreeing to indemnify Transocean against liability related to the Incident and by not paying certain invoices. Transocean also asserted claims against BP under state law, maritime law, and OPA 90 for contribution.

On 20 April 2011, BP filed claims against Cameron International Corporation (Cameron), Halliburton Energy Services, Inc. (Halliburton), and Transocean in the DoJ Action, seeking contribution for any assessments against BP under OPA 90 based on those entities fault. On 20 June 2011, Cameron and Halliburton moved to dismiss BP s claims against them in the DoJ Action. BP s claim against Cameron has been resolved pursuant to settlement (described below), but Halliburton s motion remains pending.

Also on 20 April 2011, BP asserted claims against Cameron, Halliburton and Transocean in the Limitation Action. BP s claims against Transocean include breach of contract, unseaworthiness of the Deepwater Horizon vessel, negligence (or gross negligence and/or gross fault as may be established at trial based upon the evidence), contribution and subrogation for costs (including those arising from litigation claims) resulting from the Incident, as well as a declaratory claim that Transocean is wholly or partly at fault for the Incident and responsible for its proportionate share of the costs and damages. BP asserted claims against Halliburton for fraud and fraudulent concealment based on Halliburton s misrepresentations to BP concerning, among other things,

the stability testing on the foamed cement used at the Macondo well; for negligence (or, if established by the evidence at trial, gross negligence) based on Halliburton s performance of its professional services, including cementing and mud logging services; and for contribution and subrogation for amounts that BP has paid in responding to the Incident, as well as in OPA 90 assessments and in payments to the plaintiffs. BP filed a similar complaint against Halliburton in federal court in the Southern District of Texas, Houston Division, and the action was transferred to MDL 2179 on 4 May 2011.

Also on 20 April 2011, Halliburton filed claims in the Limitation Action seeking indemnification from BP for claims brought against Halliburton in that action. Halliburton also asserted a claim for negligence, gross negligence and wilful misconduct against BP and others.

On 31 January 2012, the judge ruled on BP s and Halliburton s indemnity motions, holding that BP is required to indemnify Halliburton for third-party claims for compensatory damages resulting from pollution that did not originate from property or equipment of Halliburton located above the surface of the land or water, regardless of whether the claims result from Halliburton s gross negligence. The court, however, ruled that BP does not owe Halliburton indemnity to the extent that Halliburton is held liable for punitive damages or for civil penalties under the Clean Water Act. The court further held that BP s obligation to defend Halliburton for third-party claims does not require BP to fund Halliburton s defence of third-party claims at this time, nor does it include Halliburton s expenses in proving its right to indemnity. The court deferred ruling on whether BP is required to indemnify Halliburton for any penalties or fines under the Outer Continental Shelf Lands Act. It also deferred ruling on whether Halliburton acted so as to invalidate the indemnity by breaching its contract with BP, by committing fraud, or by committing another act that materially increased the risk to BP or prejudiced the rights of BP as an indemnitor. On 4 September 2014, as part of its findings of fact and conclusions of law for Phase one of the Trial of Liability Limitation Exoneration and Fault Allocation in MDL 2179 (Phase 1 Ruling), the court ruled that Halliburton s indemnity and release clauses in its contract with BP are valid and enforceable against BP.

On 30 May 2011, Transocean filed claims against BP in the DoJ Action alleging that BPAPC had breached its contract with Transocean Holdings LLC by not agreeing to indemnify Transocean against liability related to the Incident. Transocean also asserted claims against BP under state law, maritime law and OPA 90 for contribution.

On 1 November 2011, Transocean filed a motion for partial summary judgment on certain claims filed in the Limitation Action and the DoJ Action between BP and Transocean, seeking an order that would bar BP s contribution claims against Transocean and require BP to defend and indemnify Transocean against all pollution claims, including those resulting from any gross negligence, and from civil fines and penalties sought by the government. On 7 December 2011, BP filed a cross-motion for summary judgment seeking an order that BP is not required to indemnify Transocean for any civil fines and penalties sought by the government or for punitive damages. On 26 January 2012, the judge ruled on BP s and Transocean s indemnity motions, holding that BP is required to indemnify Transocean for third-party claims for compensatory damages resulting from pollution originating beneath the surface of the water, regardless of whether the claim results from Transocean s strict liability, negligence or gross negligence. The court, however, ruled that BP is not required to indemnify Transocean for such claims to the extent Transocean is held liable for punitive damages or for civil penalties under the Clean Water Act, or if Transocean acted with intentional or wilful misconduct in excess of gross negligence. The court further held that BP s obligation to defend Transocean for third-party claims does not require BP to fund Transocean s defence of third-party claims at this time, nor does it include Transocean s expenses in proving its right to indemnity. The court deferred a final ruling on the question of whether Transocean breached its drilling contract with BP so as to invalidate the contract s indemnity clause. On 4 September 2014, as part of its Phase 1 Ruling, the court ruled that Transocean s indemnity and release clauses in its contract with BP are valid and enforceable against BP.

On 8 December 2011, the US brought a motion for partial summary judgment in the DoJ Action seeking, among other things, an order finding that BPXP, Transocean and Anadarko are strictly liable for a civil penalty

« Defined on page 252.

under Section 311(b) (7)(A) of the Clean Water Act. On 22 February 2012, the judge ruled on motions filed in the DoJ Action by the US, Anadarko, and Transocean seeking early rulings regarding the liability of BPXP, Anadarko and Transocean under OPA 90 and the Clean Water Act, but limited the order to addressing the discharge of hydrocarbons occurring under the surface of the water. Regarding OPA 90, the judge held that BPXP and Anadarko are responsible parties under OPA 90 with regard to the subsurface discharge. The judge ruled that BPXP and Anadarko have joint and several liability under OPA 90 for removal costs and damages for such discharge, but did not rule on whether such liability under OPA 90 is unlimited. While the judge held that Transocean is not a responsible party under OPA 90 for subsurface discharge, the judge left open the question of whether Transocean may be liable under OPA 90 for removal costs for such discharge as the owner/operator of the Deepwater Horizon. Regarding the Clean Water Act, the judge held that the subsurface discharge was from the Macondo well, rather than from the Deepwater Horizon, and that BPXP and Anadarko are liable for civil penalties under Section 311 of the Clean Water Act as owners of the well. Anadarko, BPXP and the US each appealed to the US Court of Appeals for the Fifth Circuit (the Fifth Circuit), and on 4 June 2014 the Fifth Circuit unanimously affirmed the district court s decision. On 21 July 2014, Anadarko and BPXP filed petitions requesting that all active judges of the Fifth Circuit review the 4 June 2014 decision. On 9 January 2015, the Fifth Circuit issued an order denying the petition for rehearing, on a 7-6 vote. Absent an extension, BPXP s deadline for seeking US Supreme Court review is 9 April 2015.

On 18 December 2012, Transocean filed a motion seeking an early ruling that it is not liable in connection with claims for compensatory or punitive damages, or claims for contribution, brought by private, state, or local government entities and based on the subsurface discharge of oil. Transocean s motion has been fully briefed but remains pending.

Also on 18 December 2012, Transocean filed a motion seeking an early ruling that it is not liable in connection with punitive damages claims brought by members of the Economic and Property Damages Settlement Class (for a description of the Economic and Property Damages Settlement Agreement, see below). On 20 December 2012, Transocean filed a motion seeking an early ruling that it is not liable in connection with BP s claims for reimbursement of payments made under the Economic and Property Damages Settlement Agreement and BP s separate claims for spill-related damages, such as lost profits from the Macondo well, which claims were assigned by BP to the Economic and Property Damages Settlement Class. On 17 January 2013, Halliburton filed motions seeking early rulings that it is not liable in connection with punitive damages claims brought by members of the Economic and Property Damages Settlement Class; that it is not liable in connection with any contribution claim for punitive damages, whether asserted by BP or by the Economic and Property Damages Settlement Class as BP s assignee; and that it is not liable in connection with claims assigned by BP to the Economic and Property Damages Settlement Class. Transocean s and Halliburton s motions have been fully briefed but remain pending.

On 1 March 2013, Transocean sought the district court s leave to supplement its pleadings to include an affirmative defence asserting that BP s representations regarding the flow rate at the Macondo well constituted an intervening and superseding cause of the oil spill for the majority of its duration. Transocean s defence claims that BP fraudulently misrepresented and concealed information regarding the flow rate at the Macondo well in late April and May 2010, as well as the likelihood of success of a top-kill approach to stopping the flow of hydrocarbons from the well, and thus prevented the implementation of alternative means of source control that Transocean asserts could have capped the well as early as May 2010. Also on 1 March 2013, Halliburton filed a motion for leave to amend its answers to assert a similar defence. On 4 March 2013, the court granted Transocean s motion to file amended answers, and it granted Halliburton s motion the following day.

Trial phases

To address certain issues asserted in or relevant to the claims, counterclaims, cross-claims, third-party claims, and comparative fault defences raised in the DoJ Action and the Limitation Action, a Trial of Liability, Limitation, Exoneration and Fault Allocation commenced in MDL 2179 on 25 February 2013. The presentation of evidence in Phase 1

addressed issues arising out of the conduct of various parties allegedly relevant to the loss of well control at the Macondo well, the ensuing fire and explosion on the Deepwater Horizon on 20 April 2010, the sinking of the vessel on 22 April 2010 and the initiation of the release of oil from the Deepwater Horizon or the Macondo well during those time periods, including whether BP or any other party was grossly negligent. After the completion of post-trial briefing, BP moved for leave to supplement the Phase 1 record to include Halliburton s agreement to plead guilty to destroying evidence relating to Halliburton s internal examination of the Incident and the US government s press release announcing the Halliburton plea agreement. The US government, the PSC and Halliburton also submitted briefs addressing the implications of Halliburton s plea agreement. On 4 September 2014 the court granted BP s motion in part, supplementing the Phase 1 trial record with the Halliburton plea agreement, the US press release, and certain other documents related to Halliburton s criminal plea. The court also found that the simulations at issue in Halliburton s criminal plea, if not deleted by Halliburton employees, would have indicated that using 6 centralizers, as opposed to 21, would not have caused cement channeling in the Macondo well and that Halliburton s deletion of the simulations was done intentionally and in bad faith.

On 4 September 2014, the court issued its Phase 1 Ruling. The court found that BPXP, BPAPC, Transocean Holdings LLC, Transocean Deepwater Inc., Transocean Offshore Deepwater Drilling Inc. (Transocean Entities), and Halliburton are each liable under general maritime law for the blowout, explosion, and oil spill from the Macondo well. The court found that the conduct of BPXP and BPAPC was reckless, and it apportioned to them 67% of the fault for the blowout, explosion, and oil spill. The court found that the conduct of the Transocean Entities was negligent and apportioned to them 30% of the fault for the blowout, explosion, and oil spill. The court found that Halliburton s conduct was negligent and apportioned to it 3% of the fault for the blowout, explosion, and oil spill.

The district court ruled that under Fifth Circuit precedent BPXP and BPAPC cannot be liable for punitive damages under general maritime law, but to the extent the standards of the First Circuit or Ninth Circuit Courts of Appeals would apply to a particular claim, the court found that BPXP would be liable for punitive damages under those rules.

With respect to the US claims against BPXP under the Clean Water Act, the district court found that the discharge of oil was the result of BPXP s gross negligence and wilful misconduct and that BPXP is therefore subject to enhanced civil penalties. The court further found that BPXP was an operator and person in charge of the Macondo well and the Deepwater Horizon vessel for the purposes of the Clean Water Act.

The district court did not find BP p.l.c. to be at fault in connection with the blowout, explosion, and oil spill, and it ruled that BP p.l.c., Transocean Ltd., and Triton Asset Leasing GmbH are not liable under general maritime law.

The district court ruled that Transocean Entities are not entitled to limit liability under the Limitation of Liability Act and that they are liable to the US for removal costs under OPA 90.

In addition, the district court ruled that the indemnity and release clauses in BP s contracts with Halliburton and Transocean Entities are valid and enforceable against BP and granted BP s motion to supplement the Phase 1 trial record with Halliburton s agreement to plead guilty to destroying evidence relating to Halliburton s internal examination of the Incident and the US government s press release announcing the Halliburton plea agreement.

On 2 October 2014, BPXP and BPAPC filed a motion with the district court to amend the findings in the Phase 1 Ruling, to alter or amend the judgment, or for a new trial on the grounds that the court s allocation of fault and findings of gross negligence and wilful misconduct relied upon testimony which had been excluded from the evidence presented at the Phase 1 trial and as to which BPXP and BPAPC did not have adequate notice and opportunity to present evidence in rebuttal. The court denied BPXP s and BPAPC s motion to amend to the Phase 1 Ruling on 13 November 2014. On 11 December 2014, BPXP and BPAPC filed a notice of appeal of the Phase 1 Ruling to the

Fifth Circuit, and subsequently notices of appeal were also filed by the PSC, Transocean, Halliburton and the State of Alabama.

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Phase 2, which commenced on 30 September 2013, addressed (1) source control issues pertaining to the conduct or inaction of BP, Transocean Entities or other relevant parties regarding stopping the release of hydrocarbons stemming from the Incident from 22 April 2010 through to approximately 19 September 2010, and (2) quantification of discharge issues pertaining to the amount of oil actually released into the Gulf of Mexico as a result of the Incident from the time when these releases began until the Macondo well was capped on approximately 15 July 2010 and then permanently cemented shut on approximately 19 September 2010. On 15 January 2015 the district court issued its Findings of Fact and Conclusions of Law for Phase 2 of the Trial of Liability, Limitation, Exoneration and Fault Allocation in MDL 2179, finding that 3.19 million barrels of oil were discharged into the Gulf of Mexico and therefore subject to a Clean Water Act penalty. In addition, the district court found that BP was not grossly negligent in its source control efforts. On 23 February 2015, BPXP filed a notice of appeal of the Phase 2 ruling to the Fifth Circuit.

In the penalty phase of the Trial of Liability, Limitation, Exoneration and Fault Allocation in MDL 2179 the district court will determine the amount of civil penalties to be assessed against BPXP and Anadarko arising under the Clean Water Act based on the court s application of the penalty factors under the Clean Water Act. The penalty phase trial commenced on 20 January 2015 and concluded on 2 February 2015. The court has established a post-trial briefing schedule for the penalty phase under which briefing is to be concluded on 24 April 2015. BP is not currently aware of the timing of the district court s ruling for the penalty phase.

The district court has wide discretion in the application of statutory penalty factors.

MOEX, Anadarko and Cameron settlements

BP announced settlement agreements in respect of all claims related to the Incident with MOEX, Anadarko and Cameron on 20 May 2011, 17 October 2011 and 16 December 2011, respectively. Under the settlement agreement with MOEX, MOEX paid BP $1.065 billion and also agreed to transfer all its 10% interest in the MC252 lease to BP. Under the settlement agreement with Anadarko, Anadarko paid BP $4 billion and also agreed to transfer all its 25% interest in the MC252 lease to BP. The settlement agreement with Anadarko grants Anadarko the opportunity for a 12.5% participation in certain future recoveries from third parties and certain insurance proceeds in the event that such recoveries and proceeds exceed $1.5 billion in aggregate. Any such payments to Anadarko are capped at a total of $1 billion. BP agreed to indemnify MOEX, Anadarko and Cameron for certain claims arising from the Incident (excluding civil, criminal or administrative fines and penalties, claims for punitive damages, and certain other claims). The settlement agreements with MOEX, Anadarko and Cameron are not an admission of liability by any party regarding the Incident.

PSC settlements

The Economic and Property Damages Settlement resolves certain economic and property damage claims, and the Medical Benefits Class Action Settlement resolves certain medical claims by response workers and certain Gulf Coast residents. The Economic and Property Damages Settlement includes a $2.3 billion BP commitment to help resolve economic loss claims related to the Gulf seafood industry (for further information see PSC Settlements Seafood Compensation Fund below) and a $57-million fund to support continued advertising that promotes Gulf Coast tourism. It also resolves property damage in certain areas along the Gulf Coast, as well as claims for additional payments under certain Master Vessel Charter Agreements entered into in the course of the Vessels of Opportunity Program implemented as part of the response to the Incident. The Economic and Property Damages Settlement does not include claims made against BP by the DoJ or other federal agencies (including under the Clean Water Act and for Natural Resource Damages under OPA 90) or by the states and local governments. Also excluded are certain other claims against BP, such as securities and shareholder claims pending in MDL 2185, and claims based solely on the deepwater drilling moratorium and/or the related permitting process.

The Medical Benefits Class Action Settlement involves payments to qualifying class members based on a matrix for certain Specified Physical Conditions, as well as a 21-year Periodic Medical Consultation Program for qualifying class members. The deadline for submitting claims under

the Medical Benefits Class Action Settlement passed on 12 February 2015. The settlement also provides that class members claiming Later-Manifested Physical Conditions may pursue their claims through a mediation/litigation process, but waive, among other things, the right to seek punitive damages. Consistent with its commitment to the Gulf, BP has also agreed as part of the Medical Benefits Class Action Settlement to provide $105 million to the Gulf Region Health Outreach Program to improve the availability, scope and quality of healthcare in certain Gulf Coast communities. This healthcare outreach programme will be available to, and is intended to benefit, class members and other individuals in those communities. BP has already funded $79.1 million for projects sponsored by this programme.

Each agreement provides that class members will be compensated for their claims on a claims-made basis, according to agreed compensation protocols in separate court-supervised claims processes. The compensation protocols under the Economic and Property Damages Settlement provide for the payment of class members economic losses and property damages related to the oil spill. In addition many economic and property damages class members will receive payments based on negotiated risk transfer premiums, which are multiplication factors designed, in part, to compensate claimants for potential future damages that are not currently known, relating to the Incident. The Economic and Property Damages Settlement and the Medical Benefits Class Action Settlement are not an admission of liability by BP. The settlements are uncapped except for economic loss claims related to the Gulf seafood industry under the Economic and Property Damages Settlement and the $105 million to be provided to the Gulf Region Health Outreach Program under the Medical Benefits Class Action Settlement.

All class member settlements under the settlement agreements are payable under the terms of the Deepwater Horizon Oil Spill Trust (Trust). Other costs to be paid from the Trust include state and local government claims, state and local response costs, natural resource damages and related claims, and final judgments and settlements. As at 31 December 2014, the aggregate cash balances in the Trust and the qualified settlement funds amounted to $5.1 billion, including $1.1 billion remaining in the Seafood Compensation Fund, from which a further $0.5 billion partial distribution started in early 2015, and $0.4 billion held for natural resource damage early restoration projects. When the cash balances in the Trust are exhausted, payments in respect of legitimate claims and other costs will be made directly by BP. See Financial statements Note 2.

The economic and property damages claims process is under court supervision through the settlement claims process established by the Economic and Property Damages Settlement. This provides that class members release and dismiss their claims against BP not expressly reserved by that agreement. The Economic and Property Damages Settlement also provides that, to the extent permitted by law, BP assigns to the PSC certain of its claims, rights and recoveries against Transocean and Halliburton for damages with protections such that Transocean and Halliburton cannot pass those damages through to BP. Under the Medical Benefits Class Action Settlement, class members release and dismiss their claims against BP covered by that settlement, except that class members do not release claims for Later-Manifested Physical Conditions.

PSC settlements appeals

Under US federal law, there is an established procedure for determining the fairness, reasonableness and adequacy of class action settlements. Pursuant to this procedure, an extensive notice programme to the public was implemented to explain the settlement agreements and class members rights, including the right to opt out of the classes, and the processes for making claims. The court conducted a fairness hearing on 8 November 2012 in which to consider, among other things, whether to grant final approval of the Economic and Property Damages Settlement and the

Medical Benefits Class Action Settlement, whether to certify the classes for settlement purposes only, and the merits of any objections to the settlement agreements. On 21 November 2012, the parties to the settlement filed a list of 13,123 individuals and entities who had submitted timely requests to opt out of the Economic and Property Damages Settlement Class and 1,638 individuals who had submitted timely requests to opt out of the Medical Benefits Settlement Class. As a result of revocations, the number of opt-outs for the Economic and Property Damages Settlement and the Medical Benefits Class Action Settlement is fewer than those reported figures.

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Following the fairness hearing, the Economic and Property Damages Settlement was approved by the district court in a final order and judgment on 21 December 2012, and the Medical Benefits Class Action Settlement was approved in a final order and judgment on 11 January 2013.

Subsequent to the district court s final order and judgment approving the Economic and Property Damages Settlement, 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 the Fifth Circuit. Additionally, a coalition of fishing and community groups (the Coalition) appealed to the Fifth Circuit from an order of the district court denying it permission to intervene in the civil action serving as the vehicle for the Economic and Property Damages Settlement and further denying it permission to take discovery regarding the fairness of that settlement. On 11 November 2013, the Fifth Circuit affirmed the district court s rulings in respect of the Coalition. On 10 January 2014, a panel of the Fifth Circuit affirmed the district court s approval of the Economic and Property Damages Settlement but left to another panel of the Fifth Circuit (the business economic loss panel, discussed further below) the question of how to interpret the Economic and Property Damages Settlement, including the meaning of the causation requirements of that agreement. BP and several Appellants filed petitions requesting that all the active judges of the Fifth Circuit review the decision to uphold approval of the settlement. On 19 May 2014, BP s en banc petition to the full court was denied by a vote of 8-5. As explained in further detail below, BP filed a certiorari petition with the US Supreme Court on 1 August 2014, which was denied on 8 December 2014.

PSC settlements Deepwater Horizon Court Supervized Settlement Program (DHCSSP) and interpretation of the Economic and Property Damages Settlement Agreement

The DHCSSP, the claims facility operating under the framework established by the Economic and Property Damages Settlement, commenced operation on 4 June 2012 under the oversight of Claims Administrator Patrick Juneau.

As part of its monitoring of payments made by the court-supervized claims processes operated by the DHCSSP, BP identified multiple business economic loss claim determinations that appeared to result from an interpretation of the Economic and Property Damages Settlement Agreement by that settlement s claims administrator that BP believed was incorrect. This interpretation produced a higher number and value of awards than the interpretation BP used in making its initial estimate of the total cost of the Economic and Property Damages Settlement. Pursuant to the mechanisms in the Economic and Property Damages Settlement Agreement, the claims administrator sought clarification on this matter from the district court in MDL 2179, and on 5 March 2013 the district court affirmed the claims administrator s interpretation of the agreement and rejected BP s position as it relates to business economic loss claims (the March 2013 Ruling).

BP appealed the district court s March 2013 Ruling and related rulings to the Fifth Circuit. On 2 October 2013, the business economic loss panel of the Fifth Circuit (by a 2-1 vote) reversed the district court s denial of BP s motion for a preliminary injunction and the district court s order affirming the claims administrator s interpretation of the settlement, remanded the case for further proceedings and ordered the district court to enter a narrowly-tailored injunction that suspended payment to claimants affected by the misinterpretation issue and who did not have actual injury traceable to loss from the Deepwater Horizon accident . The business economic loss panel also retained jurisdiction to review the district court s conclusions on remand.

On 18 October 2013, the district court issued a preliminary injunction 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.

On 24 December 2013, the district court ruled on the two issues remanded to it in October 2013 by the business economic loss panel of the Fifth Circuit (the December 2013 Ruling): (1) requiring the claims administrator, in administering business economic loss claims, to match

revenue with corresponding variable expenses (the matching issue), and (2) determining whether the settlement agreement can properly be interpreted to permit payment to business economic loss claimants whose losses (if any) were not caused by the spill (the causation issue).

As to the matching issue, the district court ordered the claims administrator to develop a revised policy addressing the matching of revenue and expenses for business economic loss claims, which would require the matching of revenue with the expenses incurred by claimants to generate that revenue, even where the revenue and expenses were recorded at different times. On 13 March 2014, the claims administrator issued a revised matching policy reflecting this order. On 5 May 2014, the district court approved the revised policy. The PSC filed a motion on 27 May 2014 seeking to alter or amend the revised policy. On 27 June 2014, the district court issued an order establishing the process for the parties and claims administrator to determine which already-determined but unpaid claims should be subject to the revised policy.

As to the causation issue, the district court ruled that the Economic and Property Damages Settlement Agreement contained no causation requirement beyond the revenue and related tests set forth in an exhibit to that agreement. The district court also held that the absence of a further causation requirement does not defeat class certification or invalidate the settlement under the federal class certification rule or Article III of the US Constitution. On 30 December 2013, BP filed a motion with the Fifth Circuit requesting an injunction that would prevent the claims administrator from making awards to claimants whose alleged injuries are not fairly traceable to the spill. In a 2-1 decision 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 filed a petition on 17 March 2014 requesting that all active Fifth Circuit judges review the business economic loss panel s 3 March 2014 decision. On 19 May 2014, the Fifth Circuit declined (in a 5-8 decision) to grant further review of the 3 March 2014 decision.

On 21 May 2014, BP asked the Fifth Circuit to stay the issuance of the mandate transferring the case back to the district court until the US Supreme Court could decide whether to review the Fifth Circuit s decision. The Fifth Circuit denied BP s request for a stay on 27 May 2014, and issued its mandate on 28 May 2014. On the same day, the district court dissolved the injunction that had halted the processing and payment of business economic loss claims and instructed the claims administrator to resume the processing and payment of claims.

On 28 May, BP filed an application with the US Supreme Court seeking to recall and stay the Fifth Circuit s mandate in order to halt the processing and payment of business economic loss claims pending further review. The US Supreme Court denied BP s application on 9 June 2014.

On 1 August 2014, BP filed a petition for certiorari with the US Supreme Court for review of the Fifth Circuit s decision upholding the district court s ruling that the Economic and Property Damages Settlement Agreement contained no causation requirement beyond the revenue and related tests set forth in an exhibit to that agreement, as well as a related decision by a different panel of the Fifth Circuit similarly interpreting the Economic and Property Damages Settlement Agreement to permit payment to business economic loss claimants whose losses (if any) were not caused by the spill. The US Supreme Court denied BP s petition for certiorari on 8 December 2014. Accordingly, the effective date of the Economic and Property Damages Settlement Agreement is 8 December 2014, and the final deadline for filing all claims other than those that fall into the Seafood Compensation Program is 8 June 2015.

On 2 September 2014, BP filed a motion seeking an order removing Patrick Juneau from his roles as claims administrator and settlement trustee for the Economic and Property Damages Settlement. On 10 November 2014, the district court denied BP s motion. BP appealed this decision to the Fifth Circuit on 18 November 2014.

For more information about BP s current estimate of the total cost of the PSC settlements, see Financial statements Note 2.

PSC settlements investigation of the DHCSSP

On 2 July 2013, the district court in MDL 2179 appointed former federal district court judge Louis Freeh as Special Master to lead an independent investigation of the DHCSSP in connection with allegations of potential ethical violations or misconduct in the DHCSSP. On 6 September 2013,

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Judge Freeh submitted a written report to the district court in which he presented his findings that the conduct of two attorneys in the office of the claims administrator may have violated federal criminal statutes regarding fraud, money laundering, conspiracy or perjury. In an order issued the same day, the court instructed Judge Freeh to promptly recommend, design, and test enhanced internal compliance, anti-corruption, anti-fraud and conflicts of interest policies and procedures, and assist the claims administrator in the implementation of such policies and procedures. On 17 January 2014, Judge Freeh submitted a second written report that described the behaviour at the DHCSSP that led to the resignations of senior staff members.

PSC settlements Seafood Compensation Fund

On 17 December 2013, BP filed a civil lawsuit in MDL 2179 against former PSC lawyer Mikal C Watts, accusing him of having fraudulently claimed to represent more than 40,000 deckhands who allegedly suffered economic injuries as a result of the Incident. BP s action alleges that BP relied on Mr Watts s representations when it agreed to pay $2.3 billion to the Seafood Compensation Fund (the Fund), which was established under the Economic and Property Damages Settlement to compensate those who earn their livelihood from Gulf waters and were directly affected by the spill, and that the Economic and Property Damages Class stands to benefit unjustly from the full distribution of the money remaining in the Fund. In addition, BP filed two motions asking the district court to suspend further distributions from the Fund and to determine the extent of the fraud and what portion, if any, of the Fund should be returned as a result. On 17 January 2014, Mr Watts filed a motion to stay the litigation pending a parallel criminal investigation and the PSC also filed a brief opposing BP s motion seeking an injunction. On 26 February 2014, the district court granted Mr Watts s motion to stay the litigation and denied BP s motion to suspend further distributions, on the basis that no further payment from the Fund was imminent. The district court deferred ruling on BP s motion seeking to determine the extent of the fraud and what portion, if any, of the Fund should be returned as a result.

On 19 September 2014, the district court designated-neutrals appointed to preside over the settlement of the seafood program (the Neutrals) submitted to the district court their report on recommendations for the Seafood Compensation Program supplement distribution (Recommendations). The Neutrals observed that there remain some claims against the Fund which have not been paid, and that BP has filed a motion which seeks a return of part of the Fund, on the basis that it is currently impossible to fully distribute the balance of the Fund. The Neutrals recommended that the district court target a $500 million partial distribution in the second round of payments using a proportionate distribution method. The district court issued an order filing the Recommendations into the court record and requiring that any objections to or comments on the Recommendations to be filed by 20 October 2014. BP filed a response asserting that the district court should not yet order second round distributions on the basis that, amongst other things, the first round distributions are not complete. On 18 November 2014, the district court approved the Neutrals Recommendations and disbursement of funds commenced in early 2015.

Medical Benefits Class Action Settlement (Medical Settlement)

The district court approved the Medical Settlement Agreement (MSA) in a final order and judgment on 11 January 2013. The effective date was 12 February 2014. As of 9 January 2015, the claims administrator under the Medical Settlement (the Medical Claims Administrator) had received 12,418 claim forms, including 11,703 for certain Specified Physical Conditions (SPCs), and has determined 774 claims to be eligible for monetary compensation totalling approximately $1,542,500. For those claimants seeking benefits under the Periodic Medical Consultation Program, approximately 8,411 claims have been determined to be eligible. The deadline for submitting claims for SPCs under the MSA was 12 February 2015. BP does not yet know the total number of claims submitted, however a large volume of such claims is anticipated. The Medical Claims Administrator issued a policy statement, with which BP agrees, classifying physical conditions first diagnosed after 16 April 2012 as Later-Manifested Physical Conditions (LMPC), which requires a class member seeking compensation to file a notice of intent to sue that allows BP the option to mediate the claim in lieu of litigation. On 23 July 2014, the district court issued an order affirming the policy statement. On 26 November 2014, the district court directed the Medical Claims

Administrator to issue another policy statement regarding the impact of the release provisions under the MSA on the filing of SPC claims and LMPC claims, which was filed on 17 December. The district court s decision to either adopt, modify or reject the policy statement remains pending.

State and local civil claims, including under OPA 90

On 12 August 2010, the State of Alabama filed a lawsuit seeking damages for alleged economic and environmental harms, including natural resource damages, civil penalties under state law, declaratory and injunctive relief, and punitive damages as a result of the Incident. On 3 March 2011, the State of Louisiana filed a lawsuit to declare various BP entities (as well as other entities) liable for removal costs and damages, including natural resource damages under federal and state law, to recover civil penalties, attorney s fees and response costs under state law, and to recover for alleged negligence, nuisance, trespass, fraudulent concealment and negligent misrepresentation of material facts regarding safety procedures and BP s (and other defendants) ability to manage the oil spill, unjust enrichment from economic and other damages to the State of Louisiana and its citizens, and punitive damages.

On 10 December 2010, the Mississippi Department of Environmental Quality issued a Complaint and Notice of Violation alleging violations of several state environmental statutes.

The Louisiana Department of Environmental Quality has issued an administrative order seeking environmental civil penalties and other relief under state law. On 23 September 2011, BP removed this matter to federal district court, and it has been consolidated with MDL 2179.

District Attorneys of 11 parishes in the State of Louisiana filed suits under state wildlife statutes seeking penalties for damage to wildlife as a result of the Incident. On 9 December 2011 and 28 December 2011, the district court in MDL 2179 granted BP s motions to dismiss the District Attorneys complaints, holding that those claims are pre-empted by the Clean Water Act. The Fifth Circuit affirmed the district court s ruling on 24 February 2014. Several of the parishes sought Supreme Court review, which BP opposed. On 20 October 2014, the US Supreme Court declined to hear the appeal.

On 14 November 2011, the district court in MDL 2179 granted in part BP s motion to dismiss the complaints filed by the states of Alabama and Louisiana. The court s order dismissed the states claims brought under state law, including claims for civil penalties and the State of Louisiana s request for a declaratory judgment under the Louisiana Oil Spill Prevention and Response Act, holding that those claims were pre-empted by federal law. It also dismissed the State of Louisiana s claims of nuisance and trespass under general maritime law. The court s order further held that the states have stated claims for negligence and products liability under general maritime law, have sufficiently alleged presentment of their claims under OPA 90 and may seek punitive damages under general maritime law.

On 9 December 2011, the district court in MDL 2179 granted in part BP s motion to dismiss a master complaint brought on behalf of local government entities. The court s order dismissed the plaintiffs state law claims and limited the types of maritime law claims the plaintiffs may pursue, but also held that the plaintiffs have sufficiently alleged presentment of their claims under OPA 90 and that certain local government entity claimants may seek punitive damages under general maritime law. The court did not, however, lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply his dismissal of the master complaint to those individual complaints.

In January 2013, the states of Alabama, Mississippi and Florida submitted or asserted claims to BP under OPA 90 for alleged losses including economic losses and property damage as a result of the Incident. 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 non-US government. These claims under OPA 90 are substantial in aggregate, and more claims are expected to be submitted. The amounts alleged in the submissions for state and local government claims total approximately $35 billion. BP will defend vigorously against these claims if adjudicated at trial. Certain of these states (including the states of Alabama, Florida, Texas and Mississippi, as described below) and local government entities have filed civil lawsuits that pertain to claims asserted by them under their earlier OPA 90 submissions to BP.

In April 2013, the states of Alabama, Florida and Mississippi each filed actions against BP related to the Incident, which have been consolidated with MDL 2179. On 19 April 2013, the State of Alabama filed an action against BP alleging general maritime law claims of negligence, gross negligence, and wilful misconduct; claims under OPA 90 seeking damages for removal costs, natural resource damages, property damage, lost tax and other revenue and damages for providing increased public services during or after removal activities; and various state law claims. The State of Alabama s complaint also seeks punitive damages.

On 20 April 2013, the State of Florida filed suit against BP and Halliburton in federal court in Florida, and its case has also been transferred to MDL 2179. Florida s complaint alleges general maritime law claims for negligence and gross negligence; OPA 90 claims for alleged lost tax revenue, other economic damages and natural resource damages; and various state law claims. Florida also seeks punitive damages.

The State of Mississippi filed both federal court and state court complaints in Mississippi against BP in April 2013. Mississippi s federal court complaint alleges OPA 90 claims against BP, Transocean and Anadarko for natural resource damages, property damage, lost tax revenue and damages for providing increased public services during or after removal activities. It asserts general maritime law claims for negligence and gross negligence against Halliburton only. Mississippi s state court complaint alleges various state law claims, including negligence, gross negligence and willful misconduct. Both Mississippi complaints seek punitive damages. The State of Mississippi s federal court action and state court action have both been consolidated with MDL 2179.

On 17 May 2013, the State of Texas filed suit against BP and others in federal court in Texas. Its complaint asserts claims under OPA 90 for natural resource damages, lost sales tax and state park revenue; claims for natural resource damages under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); and claims for natural resource damages, cost recovery, civil penalties and economic damages under state environmental statutes. The State of Texas s action has been consolidated with MDL 2179.

On 14 February 2014, BP moved to strike the State of Alabama s jury trial demand as to its claim for compensatory damages under OPA 90. BP s motion remains pending.

On 5 March 2014, the State of Florida filed a lawsuit (which has since been consolidated with MDL 2179) to declare various BP entities (and other entities) liable for removal costs and natural resource damages.

OPA Test Case Proceedings

Seven OPA test cases will address certain OPA 90 liability questions focusing on, among other issues, whether plaintiffs alleged losses tied to the 2010 federal government moratoria on deepwater drilling and federal permit delays are compensable. On 3 June 2014 the district court entered an Agreed Upon Scheduling Order for these test cases. That scheduling order has now been suspended indefinitely with no new deadlines being established.

State of Alabama Damages Case Proceedings

On 16 July 2014 the district court issued a scheduling order for the State of Alabama s economic damages claims against BP and other parties and a request by the district court for the parties to set aside the month of November 2015 for a trial. That scheduling order has now been suspended indefinitely with no new deadlines being established.

Agreement for early natural resource restoration

On 21 April 2011, BP announced an agreement with natural resource trustees for the US and five Gulf Coast states, providing for up to $1 billion to be spent on early restoration projects to address natural resource injuries resulting from the Incident. Funding for these projects will come from the $20-billion Trust fund. BP and the trustees have reached agreement on a total of 54 early restoration projects that are expected to cost approximately $698 million. These include 10 projects that are already in place or underway, and 44 projects that were filed with

the court on 2 October 2014, following a regulatory review and public comment process. As part of the project agreements, BP will receive Natural Resource Damages (NRD) restoration credits that can be used to offset related NRD restoration obligations, either in whole or in part.

Other civil complaints

On 26 August 2011, the district court in MDL 2179 granted in part BP s motion to dismiss a master complaint raising claims for economic loss by private plaintiffs, dismissing the plaintiffs state law claims and limiting the types of maritime law claims the plaintiffs may pursue, but also held that certain classes of claimants may seek punitive damages under general maritime law. The court did not, however, lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply its dismissal of the master complaint to those individual complaints. On 30 September 2011, the court granted in part BP s motion to dismiss a master complaint asserting personal injury claims on behalf of persons exposed to crude oil or chemical dispersants, dismissing the plaintiffs state law claims, claims by seamen for punitive damages, claims for medical monitoring damages by asymptomatic plaintiffs, claims for battery and nuisance under maritime law, and claims alleging negligence per se. As with its other rulings on motions to dismiss master complaints, the court did not lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply its dismissal of the master complaint to those individual complaints.

Citizens groups have also filed either lawsuits or notices of intent to file lawsuits seeking civil penalties and injunctive relief under the Clean Water Act and other environmental statutes. On 16 June 2011, the district court in MDL 2179 granted BP s motion to dismiss a master complaint raising claims for injunctive relief under various federal environmental statutes brought by various citizens groups and others.

The court did not, however, lift an earlier stay on the underlying individual complaints raising those claims for injunctive relief or otherwise apply its dismissal of the master complaint to those individual complaints. In addition, a different set of environmental groups filed a motion to reconsider dismissal of their Endangered Species Act claims on 14 July 2011. That motion remains pending.

On 31 January 2012, the district court in MDL 2179, on motion by the Center for Biological Diversity, entered final judgment on the basis of the 16 June 2011 order with respect to two actions brought against BP by that plaintiff. On 2 February 2012, the Center for Biological Diversity filed a notice of appeal of both actions to the Fifth Circuit. Following oral argument, the Fifth Circuit ruled in BP s favour on 9 January 2013 in virtually all respects, though it remanded the Center for Biological Diversity s claim under the Emergency Planning and Community Right to Know Act (EPCRA) to the district court. On 22 January 2013, the Center for Biological Diversity filed a Petition for Panel Rehearing in the Fifth Circuit, which was denied on 4 February 2013. In January 2014, the district court in MDL 2179 set a schedule for proceedings on remand of the EPCRA claim under which limited discovery has taken place, and the parties filed cross-motions for summary judgment that were fully briefed by 19 May 2014. The district court has not acted and the cross motions remain to be decided.

Halliburton lawsuits

On 19 April 2011, Halliburton filed a lawsuit in Texas state court seeking indemnification from BPXP for certain tort and pollution-related liabilities resulting from the Incident. On 3 May 2011, BPXP removed Halliburton s case to federal court, and on 9 August 2011, the action was transferred to MDL 2179.

On 1 September 2011, Halliburton filed an additional lawsuit against BP in Texas state court alleging that BP did not identify the existence of a purported hydrocarbon zone at the Macondo well to Halliburton in connection with Halliburton s cement work performed before the Incident and that BP has concealed the existence of this purported hydrocarbon zone following the Incident. Halliburton claims that the alleged failure to identify this information has harmed its business ventures and reputation and resulted in lost profits and other damages. On 7 February 2012, the lawsuit was transferred to MDL 2179.

Non-US government lawsuits

On 15 September 2010, three Mexican states bordering the Gulf of Mexico (Veracruz, Quintana Roo and Tamaulipas) filed lawsuits in federal court in Texas against several BP entities. These lawsuits were subsequently transferred to MDL 2179 on 4 November 2010. These lawsuits allege that the Incident harmed their tourism, fishing and commercial shipping industries (resulting in, among other things, diminished tax revenue), damaged natural resources and the environment and caused the states to incur expenses in preparing a response to the Incident. On 9 December 2011, the district court in MDL 2179 granted in part BP s motion to dismiss the three Mexican states complaints, dismissing their claims under OPA 90 and for nuisance and negligence per se, and preserving their claims for negligence and gross negligence only to the extent there has been a physical injury to a proprietary interest of the states. On 12 September 2013, the court issued a final judgment dismissing the three Mexican states claims with prejudice. On 4 October 2013, the three Mexican states filed notices of appeal from the judgment to the Fifth Circuit. Following briefing, oral argument was heard on the appeal on 27 October 2014 and the appeal is now under review.

On 5 April 2011, the State of Yucatan submitted a claim to the Gulf Coast Claims Facility (GCCF) alleging potential damage to its natural resources and environment, and seeking to recover the cost of assessing the alleged damage. On 18 September 2013, the State of Yucatan filed suit against BP in federal court in Florida and, on 13 December 2013, its action was transferred to MDL 2179.

On 19 April 2013, the Mexican federal government filed a civil action against BP and others in MDL 2179. The complaint seeks a determination that each defendant bears liability under OPA 90 for damages that include the costs of responding to the spill; natural resource damages allegedly recoverable by Mexico as an OPA 90 trustee; and the net loss of taxes, royalties, fees or net profits.

Insurance-related matters

On 1 March 2012, the district court in MDL 2179 issued a partial final judgment dismissing with prejudice certain claims by BP, Anadarko and MOEX for additional insured coverage under insurance policies issued to Transocean for the sub-surface pollution liabilities BP, Anadarko and MOEX have incurred and will incur with respect to the Macondo well oil release. BP filed a notice of appeal from the district court s judgment to the Fifth Circuit and on 1 March 2013, the Fifth Circuit reversed the district court s judgment, rejecting the district court s ruling that the insurance that BP is entitled to receive as an additional insured under the Transocean insurance policies at issue is limited to the scope of the indemnity in the drilling contract between BP and Transocean. On 29 August 2013, the Fifth Circuit withdrew its 1 March 2013 opinion and certified two questions of Texas law at issue in the appeal to the Supreme Court of Texas. On 13 February 2015 the Supreme Court of Texas held that the insurance BP is entitled to receive as an additional assured is limited to the liabilities that Transocean assumed in the drilling contract which does not include liabilities for damages arising from sub-surface pollution.

False Claims Act actions

BP is aware that actions have been or may be brought under the Qui Tam (whistle-blower) provisions of the False Claims Act (FCA). On 17 December 2012, the court ordered unsealed one complaint that had been filed in the US District Court for the Eastern District of Louisiana by an individual under the FCA s Qui Tam provisions. The complaint alleged that BP and another defendant had made false reports and certifications of the amount of oil released into the Gulf of Mexico following the Incident. On 17 December 2012, the DoJ filed with the court a notice that the DoJ elected to decline to intervene in the action. On 31 January 2013, the complaint was transferred to MDL 2179 and remains stayed.

MDL 2185 and other securities-related litigation

Since the Incident, shareholders have sued BP and various of its current and former officers and directors asserting shareholder derivative claims and class and individual securities fraud claims. Many of these lawsuits have been consolidated or co-ordinated in federal district court in Houston (MDL 2185).

Securities class action

On 13 February 2012, the federal district court in Houston in MDL 2185 issued two decisions (the February 2012 ruling) on the defendants motions to dismiss the two consolidated securities fraud complaints filed on behalf of purported classes of BP ordinary shareholders and ADS holders. The February 2012 ruling dismissed all the claims of the ordinary shareholders, and the claims of the lead class of ADS holders against

most of the individual defendants while holding that a subset of the claims against two individual defendants and the corporate defendants could proceed. In addition, all of the claims of a smaller purported subclass were dismissed with leave to re-plead in 20 days. On 2 April 2012, the plaintiffs in the lead class and subclass filed an amended consolidated complaint with claims based on (1) the 12 alleged misstatements that the court held were actionable in the February 2012 ruling; and (2) 13 alleged misstatements concerning BP s operating management system that the judge either rejected with leave to re-plead or did not address in the February 2012 ruling. On 2 May 2012, defendants moved to dismiss the claims based on the 13 statements in the amended complaint that the judge did not already rule are actionable. On 6 February 2013, the court granted in part this motion to dismiss, rejecting the plaintiffs claims based on eight of the statements at issue in the motion and also dismissing all claims against former BP employee Andrew Inglis. On 20 May 2014, the judge denied plaintiffs motion to certify a proposed class of ADS purchasers before the Deepwater Horizon explosion (from 8 November 2007 to 20 April 2010) and granted plaintiffs motions to certify a class of post-explosion ADS purchasers from 26 April 2010 to 28 May 2010 and to amend their complaint to add one additional alleged misstatement. Both parties sought permission to appeal from the district court s class certification decisions and on 3 July 2014, the Fifth Circuit granted both parties requests. Briefing on those appeals is expected to conclude in March 2015.

The trial of the securities fraud claims of the class of post-explosion ADS purchasers has been scheduled to commence on 11 January 2016.

Individual securities litigation

In April and May 2012, six cases (three of which were consolidated into one action) were filed in state and federal courts by one or more state, county or municipal pension funds against BP entities and several current and former officers and directors seeking damages for alleged losses those funds suffered because of their purchases of BP ordinary shares and, in two cases, ADSs. The funds assert various state law and federal law claims. From July 2012 to April 2014, 27 additional cases were filed in Texas state and federal courts (later consolidated into 24 actions) by pension or investment funds or advisers against BP entities and current and former officers and directors, asserting state, federal, and non-US law claims and seeking damages for alleged losses that those funds suffered because of their purchases of BP ordinary shares and/or ADSs. Two cases were filed in New York federal court by funds that purchased BP ordinary shares and ADSs, asserting state and federal law claims. All the cases have been transferred to federal court in Houston and, with the exception of one case that has been stayed, the judge presiding over MDL 2185. One case was voluntarily dismissed on 9 May 2013. On 3 October 2013, the judge granted in part and denied in part the defendants motion to dismiss three of the remaining 29 cases dismissing a subset of the claims. The judge held that English law governs the plaintiffs remaining claims (with the exception of the federal law claims based on purchases of ADSs and a potential claim under Ohio state law against BP p.l.c. by certain Ohio funds). On 11 December 2013, defendants moved to dismiss 10 of the remaining cases and answered the complaints in two others. On 5 December 2013, the Ohio funds (plaintiffs in one of the first three cases defendants moved to dismiss) filed an amended complaint withdrawing their English law claim and asserting only a claim under Ohio state law. On 6 January 2014, BP moved to dismiss that case for a second time, and on 7 April 2014, the judge dismissed the Ohio action with leave to replead English law claims within 30 days. On 8 June 2014, the Ohio funds filed a second amended complaint asserting only English law claims. On 30 September 2014, the court granted in part and denied in part the defendants motion to dismiss 10 cases. The court dismissed the negligent misstatement claims in all but one of the 10 cases and dismissed claims in these cases based on certain public and private misstatements. The court also rejected BP s arguments that the ordinary share claims of the non-US plaintiffs should be heard in England. On 29 October 2014, the case brought by the Ohio funds was transferred to federal court in Houston for all purposes. On 30 December 2014, defendants answered the complaints in 11 cases. Amended complaints in the remaining 15 cases are due by 1 April 2015.

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Canadian class action

On 20 July 2012, a BP entity received an amended statement of claim for an action in Alberta, Canada, filed by three plaintiffs seeking to assert claims under Canadian law against BP on behalf of a class of Canadian residents who allegedly suffered losses because of their purchase of BP ordinary shares and ADSs. This case was dismissed on jurisdictional grounds on 14 November 2012. On 15 November 2012, one of the plaintiffs re-filed a statement of claim against BP in Ontario, Canada, seeking to assert the same claims against BP. BP moved to dismiss that action for lack of jurisdiction, and on 9 October 2013 the Ontario court denied BP s motion. On 7 November 2013, BP filed a notice of appeal from that decision. On 14 August 2014, the Ontario Court of Appeal held that the case should be stayed and that the claims made on behalf of Canadian residents who purchased BP ordinary shares and ADSs on exchanges outside of Canada should be litigated in those countries, and granted leave for the plaintiff to amend the complaint to assert claims only on behalf of Canadian residents who purchased ADSs on the Toronto Stock Exchange. On 10 October 2014, the plaintiff filed an application for leave to appeal to the Supreme Court of Canada. Briefing on that application concluded on 25 November 2014.

Dividend-related proceedings

On 5 July 2012, the federal district court in Houston in MDL 2185 issued a decision granting BP s motion to dismiss, for lack of personal jurisdiction, the lawsuit against BP p.l.c. for cancelling its dividend payment in June 2010. On 10 August 2012, the plaintiffs filed an amended complaint, which BP moved to dismiss on 9 October 2012. On 12 April 2013, the court granted BP s motion and dismissed the lawsuit for lack of personal jurisdiction and on the alternative grounds of failure to state a claim and that the courts of England are the more appropriate forum for the litigation. On 16 June 2013, the court granted the plaintiff s motion to amend its decision so as to eliminate the alternative grounds for dismissal. On 22 November 2013, the plaintiffs filed an additional and substantially identical action against BP p.l.c. in federal court in New York, which was transferred to the judge presiding over MDL 2185. BP p.l.c. moved to dismiss that action on 19 February 2014. On 18 June 2014, the court dismissed the case on the ground that the courts of England are the more appropriate forum for the litigation. On 18 July 2014, the plaintiff appealed that decision to the Fifth Circuit. Briefing on that appeal concluded on 24 December 2014.

ERISA

On 30 March 2012, the federal district court in Houston in MDL 2185 issued a decision granting the defendants motions to dismiss the ERISA case related to BP share funds in several employee benefit savings plans. On 11 April 2012, the plaintiffs requested leave to file an amended complaint, which was denied on 27 August 2012. Final judgment dismissing the case was entered on 4 September 2012 and, on 25 September 2012, the plaintiffs filed a notice of appeal to the Fifth Circuit. On 15 July 2014, the Fifth Circuit remanded the case to the district court in light of new pleading standards recently set forth by the US Supreme Court. On 18 September 2014, the plaintiffs filed a motion seeking leave to amend their complaint. Defendants opposed that motion. On 15 January 2015, the district court granted in part and denied in part the motion to amend, permitting plaintiffs to amend their complaint to allege some of their proposed claims against certain defendants. Plaintiffs filed an amended complaint on 12 February 2015.

Settlements with the DoJ and SEC

On 1 June 2010, the DoJ announced that it was conducting an investigation into the Incident encompassing possible violations of US civil or criminal laws, and subsequently created a unified task force of federal agencies to investigate the Incident. On 15 November 2012, BP announced that it reached agreement with the US government, subject to court approval, to resolve all federal criminal charges and all claims by the SEC against BP arising from the Deepwater Horizon accident, oil spill and response.

On 29 January 2013, the US District Court for the Eastern District of Louisiana accepted BP s pleas regarding the federal criminal charges, and BP was sentenced in connection with the criminal plea agreement. BP pleaded guilty to 11 felony counts of Misconduct or Neglect of Ships Officers relating to the loss of 11 lives; one misdemeanour count under

the Clean Water Act; one misdemeanour count under the Migratory Bird Treaty Act; and one felony count of obstruction of Congress.

Pursuant to that sentence, BP will pay $4 billion, including $1,256 million in criminal fines, in instalments over five years. Under the terms of the criminal plea agreement, a total of $2,394 million will be paid to the National Fish & Wildlife Foundation (NFWF) over five years. In addition, $350 million will be paid to the National Academy of Sciences (NAS) over five years. BP made its required payments that were due in March and April 2013, January 2014, and January 2015 totalling $1.521 billion. The court also ordered, as previously agreed with the US government, that BP serve a term of five years probation. Pursuant to the terms of the plea agreement, the court also ordered certain equitable relief, including additional actions, enforceable by the court, to further enhance the safety of drilling operations in the Gulf of Mexico. These requirements relate to BP s risk management processes, such as third-party auditing and verification, BP s oil spill response plan, training, and well control equipment and processes such as blowout preventers and cementing. BP also agreed to maintain a real-time drilling operations monitoring centre in Houston or another appropriate location. In addition, BP will undertake several initiatives with academia and regulators to develop new technologies related to deepwater drilling safety. The resolution also provides for the appointment of two monitors, both with terms of up to four years. A process safety monitor will review, and provide recommendations concerning BPXP s process safety and risk management procedures for deepwater drilling in the Gulf of Mexico. An ethics monitor will review and provide recommendations concerning BP s ethics and compliance programme. BP has also agreed to retain an independent third-party auditor who will review and report to the probation officer, the DoJ and BP regarding BPXP s compliance with the key terms of the plea agreement 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. Under the plea agreement, BP has also agreed to co-operate in ongoing criminal actions and investigations, including prosecutions of four former employees who have been separately charged.

In its resolution with the SEC, BP has resolved the SEC s Deepwater Horizon-related claims against the company under Sections 10(b) and 13(a) of the Securities Exchange Act of 1934 and the associated rules. BP has agreed to a civil penalty of $525 million, payable in three instalments over a period of three years, and has consented to the entry of an injunction prohibiting it from violating certain US securities laws and regulations. The SEC s claims are premised on oil flow rate estimates contained in three reports provided by BP to the SEC during a one-week period (on 29 and 30 April 2010 and 4 May 2010), within the first 14 days after the accident. BP s consent was incorporated in a final judgment and court order on 10 December 2012, and BP made its first payment of $175 million on 11 December 2012, its second payment of $175 million on 1 August 2013, and the final instalment of $175 million, plus accrued interest, on 1 August 2014.

BP s November 2012 agreement with the US government does not resolve the DoJ s civil claims, such as those for civil penalties under the Clean Water Act or claims for natural resource damages under OPA 90. Neither does it resolve the private securities claims pending in MDL 2185.

US Environmental Protection Agency matters

On 28 November 2012, the US Environmental Protection Agency (EPA) notified BP that it had temporarily suspended BP p.l.c., BPXP and a number of other BP subsidiaries from participating in new federal contracts. As a result of the temporary suspension, the BP entities listed in the notice were ineligible to receive any US government contracts either through the award of a new contract, or the extension of the term of or renewal of an expiring contract.

In addition, the charges to which BPXP pleaded guilty included one misdemeanour count under the Clean Water Act that, by operation of law, triggered a statutory debarment, also referred to as mandatory debarment, of the facility where the Clean Water Act violation occurred. On 1 February 2013, the EPA issued a notice that BPXP was mandatorily debarred at its Houston headquarters. Mandatory debarment prevents a company from entering into new contracts or new leases with the US government that would be performed at the facility where the Clean Water Act violation occurred.

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On 13 March 2014, BP, BPXP, and all other temporarily suspended BP entities entered into an administrative agreement with the EPA resolving all issues related to suspension or debarment arising from the Incident, allowing BP entities to enter into new contracts or leases with the US government. Under the terms and conditions of the administrative agreement, which will apply for five years, BP has agreed to a set of safety and operations, ethics and compliance and corporate governance requirements.

US Department of Interior matters

On 14 September 2011, the US Coast Guard and Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) issued a report regarding the causes of the 20 April 2010 Macondo well blowout (the BOEMRE Report). The BOEMRE Report states that decisions by BP, Halliburton and Transocean increased the risk or failed to fully consider or mitigate the risk of a blowout on 20 April 2010. The BOEMRE Report also states that BP, Transocean and Halliburton violated certain regulations related to offshore drilling. In itself, the BOEMRE Report does not constitute the initiation of enforcement proceedings relating to any violation. On 12 October 2011, the US Department of the Interior Bureau of Safety and Environmental Enforcement issued to BPXP, Transocean, and Halliburton Notification of Incidents of Noncompliance (INCs). The notification issued to BPXP is for a number of alleged regulatory violations concerning Macondo well operations. The Department of Interior has indicated that this list of violations may be supplemented as additional evidence is reviewed, and on 7 December 2011, the Bureau of Safety and Environmental Enforcement issued to BPXP a second INC. This notification was issued to BP for five alleged violations related to drilling and abandonment operations at the Macondo well. BP has filed an administrative appeal with respect to the first and second INCs. BP has filed a joint stay of proceedings with the Department of Interior with respect to both INCs.

Louisiana Department of Natural Resources

On 21 August 2013, the Louisiana Department of Natural Resources (LDNR) issued a Cease and Desist Order (the Order) directing BP to apply for a Coastal Use Permit to remove certain orphan anchors that had been placed in coastal waters to secure the containment boom during oil spill response operations in 2010. On 18 September 2013, BP filed a complaint in the US District Court for the Middle District of Louisiana seeking to enjoin the State of Louisiana from enforcing the Order on grounds including that the Order is pre-empted by federal law. On 7 August 2014, the court entered a final judgment providing that the Order was pre-empted on the basis of impossibility and obstacle pre-emption. The LDNR did not file a notice of appeal and the time period to file such notice has expired.

Pending investigations and reports relating to the Deepwater Horizon oil spill CSB investigation

The US Chemical Safety and Hazard Investigation Board (CSB) conducted an investigation of the Incident that is focused on the explosions and fire, and not the resulting oil spill or response efforts. As part of this effort, on 24 July 2012, the CSB conducted a hearing at which it released its preliminary findings on, among other things, the use of safety indicators by industry (including BP and Transocean) and government regulators in offshore operations prior to the Incident. On 18 September 2014, in response to Transocean s challenge to the CSB s jurisdiction to investigate the Incident, the Fifth Circuit affirmed the district court s order enforcing CSB s administrative subpoenas against Transocean. BP has produced documents in compliance with the CSB s document subpoenas. Separately the CSB released the first two volumes of its three-volume report on its investigation into the Incident at a public hearing in Houston on 5 June 2014. The first two volumes provide an introduction to the Incident as well as the CSB s findings regarding the operation of the blowout preventer and other technical issues. The CSB has indicated that it plans to release Volume 3 (concerning the role of the regulator in the oversight of the offshore industry and organizational and cultural factors) in or around March 2015.

Other legal proceedings

FERC and CFTC matters

The US Federal Energy Regulatory Commission (FERC) and the US Commodity Futures Trading Commission (CFTC) have been investigating

several BP entities regarding trading in the next-day natural gas market at Houston Ship Channel during September, October and November 2008. On 28 July 2011, FERC staff issued a Notice of Alleged Violations stating that it had preliminarily determined that several BP entities fraudulently traded physical natural gas in the Houston Ship Channel and Katy markets and trading points to increase the value of their financial swing spread positions. On 5 August 2013, the FERC issued an Order to Show Cause and Notice of Proposed Penalty directing BP to respond to a FERC Enforcement Staff report, which FERC issued on the same day, alleging that BP manipulated the next-day, fixed price gas market at Houston Ship Channel from mid-September 2008 to 30 November 2008. The FERC Enforcement Staff report proposes a civil penalty of $28 million and the surrender of $800,000 of alleged profits. BP filed its answer on 4 October 2013 denying the allegations and moving for dismissal. On 15 May 2014, FERC denied the motion to dismiss and the matter has been set for a hearing before an Administrative Law Judge in March 2015.

Canadian Natural Resource

The US Commodity Futures Trading Commission (CFTC) is currently investigating certain practices relating to crude oil pipeline nominations procedures on Canadian pipelines. On 17 November 2014, the CFTC Enforcement Staff notified BP that it intends to recommend an enforcement action naming certain parties, including several BP entities, alleging violations of the anti-fraud and false reporting provisions of the Commodity Exchange Act in connection with these nomination procedures and related trades. On 17 December 2014 BP submitted a detailed defence responding to the allegations in the notice and challenging the CFTC s jurisdiction over the alleged conduct.

Investigations by the FERC and CFTC into BP s trading activities continue to be conducted from time to time.

CSB matters

On 23 March 2005, an explosion and fire occurred at the Texas City refinery. Fifteen workers died in the incident and many others were injured. BP Products North America, Inc. (BP Products) has resolved all civil injury claims and all civil and criminal governmental claims arising from the March 2005 incident. In March 2007, the US Chemical Safety and Hazard Investigation Board (CSB) issued a report on the incident. The report contained recommendations to the Texas City refinery and to the board of directors of BP. To date, the CSB has accepted that the majority of BP s responses to its recommendations have been satisfactorily addressed. BP and the CSB are continuing to discuss the remaining open recommendations with the objective of the CSB agreeing to accept these as satisfactorily addressed as well.

OSHA matters

On 29 October 2009, the US Occupational Safety and Health Administration (OSHA) issued citations to the Texas City refinery related to the Process Safety Management (PSM) standard. On 12 July 2012, OSHA and BP resolved 409 of the 439 citations. The agreement required that BP pay a civil penalty of $13,027,000 and that BP abate the alleged violations by 31 December 2012. BP completed these requirements and the agreement has terminated. The settlement excluded 30 citations for which BP and OSHA could not reach agreement. However, the parties agreed that BP s penalty liability will not exceed $1 million if those citations are resolved through litigation. On 4 March 2014, the parties reached agreement in relation to the remaining Texas City citations. The agreement links the outcome of the remaining Texas City citations to the ultimate outcome of the remaining Toledo citations (see below). If the 31 July 2013 decision of the Administrative Law Judge in relation to the remaining Toledo citations is ultimately upheld, OSHA has agreed to dismiss the remaining Texas City citations.

If the 31 July 2013 decision is ultimately overturned, BP has agreed to pay a penalty not exceeding $1 million to resolve the remaining Texas City citations.

On 8 March 2010, OSHA issued 65 citations to BP Products and BP-Husky for alleged violations of the PSM standard at the Toledo refinery, with penalties of approximately $3 million. These citations resulted from an inspection conducted pursuant to OSHA s Petroleum Refinery Process Safety Management National Emphasis Program. Both BP Products and BP-Husky contested the citations. The parties resolved 23 citations in a pre-trial settlement for an aggregate amount of $45,000. A trial of the remaining 42 citations was completed in June 2012 before an Administrative Law Judge from the OSH Review Commission. The Administrative Law Judge rendered her decision on 31 July 2013. Of the 42 remaining citations, OSHA voluntarily dismissed one of them and the judge vacated 36 additional citations. The remaining five citations were downgraded and assessed an aggregate penalty of $35,000. In addition, the judge accepted the parties pre-trial settlement of the 23 citations. As a result of the settlement and the judge s decision, the total penalty in respect of the citations was reduced from the original amount of approximately $3 million to $80,000. The Review Commission has granted OSHA s petition for review and briefing was completed in the first half of 2014. The Review Commission is not expected to issue its decision until 2015 at the earliest.

Prudhoe Bay leak

In March and August 2006, oil leaked from oil transit pipelines operated by BP Exploration (Alaska) Inc. (BPXA) at the Prudhoe Bay unit on the North Slope of Alaska. On 12 May 2008, a BP p.l.c. shareholder filed a consolidated complaint alleging violations of federal securities law on behalf of a putative class of BP p.l.c. shareholders, based on alleged misrepresentations concerning the integrity of the Prudhoe Bay pipeline before its shutdown on 6 August 2006. The BP p.l.c. shareholder filed an amended complaint, in response to which BP filed a motion to dismiss, which was granted by the trial court on 14 March 2012. The plaintiff appealed the court s dismissal of the case, and on 13 February 2014 the Ninth Circuit affirmed in part and reversed in part, ruling that claims based on four alleged misrepresentations should not have been dismissed. The case has been remanded to the trial court for further proceedings.

Exxon Valdez matters

Approximately 200 lawsuits were filed in state and federal courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP s combination with Atlantic Richfield. Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages that it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, BP will defend the claims vigorously.

Lead paint matters

Since 1987, Atlantic Richfield Company (Atlantic Richfield), a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting and Refining and another company that manufactured lead pigment during the period 1920-1946. The plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits seek various remedies including compensation to lead-poisoned children, cost to find and remove lead paint from buildings, medical monitoring and screening programmes, public warning and education of lead hazards, reimbursement of government healthcare costs and special education for lead-poisoned citizens and punitive damages. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences. It intends to defend such actions vigorously and believes that the incurrence of liability is remote. Consequently, BP believes that the impact of these lawsuits on the group s results, financial position or liquidity will not be material.

Abbott Atlantis related matters

In April 2009, Kenneth Abbott, as relator, filed a US False Claims Act lawsuit against BP, alleging that BP violated federal regulations, and made false statements in connection with its compliance with those regulations, by failing to have necessary documentation for the Atlantis

subsea and other systems. BP is the operator and 56% interest owner of the Atlantis unit which is in production in the Gulf of Mexico. On 21 August 2014, the court granted BP s motions for summary judgment. On 28 August 2014, the court entered final judgment in favour of BP. In September 2014 the plaintiff filed a motion for reconsideration, which BP opposed. The judge took this on advisement. A decision of the court is awaited.

Bolivia

In respect of Pan American Energy s arbitration case for compensation for the expropriation of its shares in Empresa Petrolera Chaco S.A. (Chaco) which commenced in March 2012 against the Republic of Bolivia, on 18 December 2014, the Republic of Bolivia and Pan American Energy signed a $357 million settlement agreement and agreed to terminate the arbitration.

EC investigation and related matters

On 14 May 2013, European Commission officials made a series of unannounced inspections at the offices of BP and other companies involved in the oil industry acting on concerns that anticompetitive practices may have occurred in connection with oil price reporting practices and the reference price assessment process. Related inquiries and requests for information have also been received from US and other regulators following the European Commission s actions, including from the Japanese Fair Trade Commission, the Korean Fair Trade Commission, the Federal Trade Commission (FTC) and the CFTC. On 1 October 2014, BP was informed by the FTC that it was closing its investigation. The other investigations remain open and there is no deadline for the completion of the inquiries.

In addition, fifteen purported class actions related to these matters have been filed in US district courts alleging manipulation and antitrust violations under the Commodity Exchange Act and US antitrust laws, and these purported class actions have been consolidated in federal court in New York.

California False Claims Act matters

On 4 November 2014 the California Attorney General filed a notice in California state court that it was intervening in a previously-sealed California False Claims Act (CFCA) lawsuit filed by relator Christopher Schroen against BP, BP Energy Company, BP Corporation North America Inc., BP Products and BPAPC. On 7 January 2015, the California Attorney General filed a complaint in intervention alleging that BP violated the CFCA and the California Unfair Competition Law by falsely and fraudulently overcharging California state entities for natural gas. The relator s complaint makes similar allegations, in addition to individual claims. The complaints seek treble damages, punitive damages, penalties and injunctive relief.

See Financial statements Note 31 for additional information on the group s legal proceedings.

International trade sanctions

During the period covered by this report, non-US subsidiaries or other non-US entities of BP conducted limited activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of

Terrorism or otherwise subject to US and EU sanctions (Sanctioned Countries). Sanctions restrictions continue to be insignificant to the group s financial condition and results of operations. BP monitors its activities with Sanctioned Countries, persons from Sanctioned Countries and individuals and companies subject to US and EU sanctions and seeks to comply with applicable sanctions laws and regulations.

Both the US and the EU have enacted strong sanctions against Iran, including: in the US, sanctions against persons involved with Iran s energy, shipping and petrochemicals industries, and sanctions against financial institutions that engage in significant transactions with the Iran Central Bank; and in the EU, a prohibition on the import, purchase and transport of Iranian-origin crude oil, petroleum products and natural gas. Additionally, the Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA) added Section 13(r) to the Securities Exchange Act of 1934, as amended (the Exchange Act), and requires that issuers must file annual or quarterly reports under the Exchange Act to disclose in such reports whether, during the period covered by the report, the registrant

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or its affiliates have knowingly engaged in certain, principally Iran-related, activities.

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

With effect from 20 January 2014, the US and the EU implemented temporary, limited and reversible relief of certain sanctions related to Iran pursuant to a Joint Plan of Action entered by Iran, China, France, Germany, Russia, the UK and the US. BP has not changed its policy in relation to Iran as a result of the Joint Plan of Action and has no plans to engage in any new business with Iran which would now be permitted as a result of the Joint Plan of Action.

BP has interests in and operates the North Sea Rhum field (Rhum) and the Azerbaijan Shah Deniz field (Shah Deniz), in which Naftiran Intertrade Co. Limited and NICO SPV Limited (collectively, NICO) or Iranian Oil Company (U.K.) Limited (IOC UK) have interests. Additionally, BP has interests in a gas marketing entity and a gas pipeline entity in which NICO or IOC UK have interests, although both entities (and their related assets) are located outside Iran. Production was suspended at Rhum (in which IOC UK has a 50% interest) in November 2010. On 22 October 2013, the UK government announced a temporary management scheme (the Temporary Scheme) under The Hydrocarbon (Temporary Management Scheme) Regulations 2013 under which the UK government assumed control of and now manages IOC UK s interest in the Rhum field, thereby permitting Rhum operations to recommence in accordance with applicable EU regulations and in compliance with US laws and regulations. Operations at the Rhum gas field recommenced in mid-October 2014 in accordance with this Temporary Scheme.

Shah Deniz, its gas marketing entity and the gas pipeline entity (in which NICO has a 10% or less non-operating interest) continue in operation. The Shah Deniz joint operation and its gas marketing and pipeline entities were excluded from the main operative provisions of the EU regulations as well as from the application of the new US sanctions, and fall within the exception for certain natural gas projects under Section 603 of ITRA.

BP has no operations in Iran and BP s policy is that it shall not purchase or ship crude oil or other products of Iranian origin. Participants in non-BP controlled or operated joint arrangements* may purchase Iranian-origin crude oil or other components as feedstock for facilities located outside the EU and US. It is also BP s policy that it shall not sell crude oil or other products into Iran. BP currently holds an interest in a non-BP operated Indian joint venture* which sold crude oil to an Indian entity in which NICO holds a minority, non-controlling stake. Those sales ceased in January 2014.

In 2012, BP became aware that a Canadian university had been using graduate students, some of whom were nationals of Iran, on a research programme funded in part by BP. BP suspended the programme and made a voluntary disclosure to OFAC. Also in 2012, BP became aware that in 2010, as consideration for certain auditing services, BP effected a transfer of funds to a local Iranian consulting firm which may have been in violation of relevant EU notification requirements. BP has made a voluntary disclosure to the applicable EU regulator of such transfer.

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

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

BP sells lubricants in Cuba through a 50:50 joint arrangement and trades in small quantities of lubricants.

During 2014 the US and the EU have imposed sanctions on certain Russian activities, individuals and entities, including Rosneft. Certain sectoral sanctions also apply to entities owned 50% or more by entities on the relevant sectoral sanctions list. Ruhr Oel GmbH (ROG) is a 50:50 joint operation with Rosneft, operated by BP, which holds interests in a number of refineries in Germany. To date, these sanctions have had no material adverse impact on BP or ROG.

Disclosure pursuant to Section 219 of ITRA

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

Rhum, located in the UK sector of the North Sea, is operated by BP Exploration Operating Company Limited (BPEOC), a non-US subsidiary of BP. Rhum is owned under a 50:50 unincorporated joint arrangement between BPEOC and Iranian Oil Company (U.K.) Limited (IOC). The Rhum joint arrangement was originally formed in 1974. During the period of production from the field, the Rhum joint arrangement supplied natural gas and certain associated liquids to the UK. On 16 November 2010, production from Rhum was suspended in response to relevant EU sanctions. Operations at the Rhum gas field recommenced in mid-October 2014 in accordance with the UK government s Temporary Scheme (see above). During the year ended 31 December 2014, BP recorded gross revenues of $8.86 million related to its interests in Rhum. BP had no net profits related to Rhum during the year ended 31 December 2014, recording an overall loss of $204.5 million (net) following an impairment write-off of $198 million in the fourth quarter of 2014.

BP currently intends to continue to hold its ownership stake in the Rhum joint arrangement.

Material contracts

On 13 March 2014, BP, BPXP, and other BP entities entered into an administrative agreement with the US Environmental Protection Agency, which resolved all issues related to the suspension or debarment of BP entities arising from the 20 April 2010 explosions and fire on the semi-submersible rig Deepwater Horizon and resulting oil spill. The administrative agreement allows BP entities to enter into new contracts or leases with the US government. Under the terms and conditions of this agreement, which will apply for five years, BP has agreed to a set of safety and operations, ethics and compliance and corporate governance requirements. The agreement is governed by federal law.

Property, plant and equipment

BP has freehold and leasehold interests in real estate and other tangible assets in numerous countries, but no individual property is significant to the group as a whole. For more on the significant subsidiaries* of the group at 31 December 2014 and the group percentage of ordinary share capital see Financial statements Note 35. For information on significant joint ventures* and associates* of the group see Financial statements Notes 14 and 15.

Related-party transactions

Transactions between the group and its significant joint ventures and associates are summarized in Financial statements Note 14 and Note 15. In the ordinary course of its business, the group enters into transactions with various organizations with which some of its directors or executive officers are associated. Except as described in this report, the group did not have material transactions or transactions of an unusual nature with, and did not make loans to, related parties in the period commencing 1 January 2014 to 17 February 2015.

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

*Defined on page 252.

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 64). 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 64). 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, officers and members of the board. This was updated (and published) in July 2014.

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 2014 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

2014 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 2014 has been audited by Ernst & Young, an independent registered public accounting firm, as stated in their report appearing on page 95 of *BP Annual Report and Form 20-F 2014*.

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Changes in internal control over financial reporting

There were no changes in the group s internal controls over financial reporting that occurred during the period covered by the Form 20-F that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Principal accountants fees and services

The audit committee has established policies and procedures for the engagement of the independent registered public accounting firm, Ernst & Young LLP, to render audit and certain assurance and tax services. The policies provide for pre-approval by the audit committee of specifically defined audit, audit-related, tax and other services that are not prohibited by regulatory or other professional requirements. Ernst & Young are engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young relative to that of other potential service providers. These services are for a fixed term.

Under the policy, pre-approval is given for specific services within the following categories: advice on accounting, auditing and financial reporting matters; internal accounting and risk management control reviews (excluding any services relating to information systems design and implementation); non-statutory audit; project assurance and advice on business and accounting process improvement (excluding any services relating to information systems design and implementation relating to BP s financial statements or accounting records); due diligence in connection with acquisitions, disposals and joint 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 34 and Audit committee report on page 64 for details of fees for services provided by auditors.)

Directors report information

This section of *BP Annual Report and Form 20-F 2014* forms part of, and includes certain disclosures which are required by law to be included in, the Directors report.

Indemnity provisions

In accordance with BP s Articles of Association, on appointment each director is granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report. In respect of those liabilities for which directors may not be indemnified, the company maintained a directors and officers liability

insurance policy throughout 2014. During the year, a review of the terms and scope of the policy was undertaken. The 2013 policy was extended into 2014 and subsequently renewed during 2014 into 2015. Although their defence costs may be met, neither the company s indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly. In addition, each director of the company s subsidiaries which subsidiaries are trustees of the group s pension schemes, is granted an indemnity from the company in respect of liabilities incurred as a result of such a subsidiary s activities as a trustee of the pension scheme, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report.

Financial risk management objectives and policies

The disclosures in relation to financial risk management objectives and policies, including the policy for hedging, are included in Our management of risk on page 46, Liquidity and capital resources on page 211 and Financial statements Notes 27 and 28.

Exposure to price risk, credit risk, liquidity risk and cash flow risk

The disclosures in relation to exposure to price risk, credit risk, liquidity risk and cash flow risk are included in Financial statements Note 27.

Important events since the end of the financial year

Disclosures of the particulars of the important events affecting BP which have occurred since the end of the financial year are included in the Strategic report as well as in other places in the Directors report.

Likely future developments in the business

An indication of the likely future developments of the business is included in the Strategic report.

Research and development

An indication of the activities of the company in the field of research and development is included in Our strategy on page 13.

Branches

As a global group our interests and activities are held or operated through subsidiaries*, branches, joint arrangements* or associates* established in and subject to the laws and regulations of many different jurisdictions.

Employees

The disclosures concerning policies in relation to the employment of disabled persons and employee involvement are included in Corporate responsibility Employees on page 44.

Employee share schemes

Certain shares held by the Employee Share Ownership Plan trusts (ESOPs) carry voting rights. Voting rights in respect of such shares are exercisable via a nominee.

Greenhouse gas emissions

The disclosures in relation to greenhouse gas emissions are included in Corporate responsibility Environment and society on page 42.

Disclosures required under Listing Rule 9.8.4R

The information required to be disclosed by Listing Rule 9.8.4R can be located as set out below:

Information required	Page
(1) Amount of interest capitalized	123
(2) (14)	Not applicable

Cautionary statement

This document contains certain forecasts, projections and forward-looking statements that is, statements related to future, not past events with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , aims , should , may , objective , is likely believes , anticipates , plans , we see or similar expressions. In particular, among other statements, (1) certain stateme in the Chairman s letter (pages 6-7), the Group chief executive s letter (pages 8-9), the Strategic report

*Defined on page 252.

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(inside front cover and pages 1-50) and Additional disclosures (pages 207- 242), including but not limited to statements under the headings Our market outlook , Beyond 2035 , Our business model , Our strategy , Outlook an Outlook for 2015 , and including but not limited to statements regarding plans and prospects relating to future value creation, capital discipline and growth in sustainable free cash flow; plans to develop resources, increase production, strengthen BP s portfolio of high-return and longer-life assets and unlock value from BP s resource base; plans relating to future workforce size, initiatives and composition, including workforce diversity; expectations regarding the future level of oil and gas prices and industry product supply, demand and pricing in the near term and long term and BP s outlook and projections of future energy trends, including the role of oil, gas and renewables therein; plans to form key partnerships and relationships with governments, customers, partners, communities, suppliers and other institutions; expectations regarding and timing of planned and future acquisitions and divestments, including the completion of $10 billion of divestments in 2015; expectations regarding the current and future prospects of BP s discoveries, resources, reserves and positions; expectations regarding BP s reported and underlying production in 2015; the timing and composition of planned and future projects including expected final investment decisions, start-up, construction, commissioning, completion, timing of production, level of production and margins of such projects; expectations regarding Rosneft s future share price and dividend growth and BP s plans to explore future opportunities with Rosneft; plans regarding growing operating cash flow and returns in Downstream, including by leveraging assets, portfolio management, customer relationships, technology and trading activity; expectations regarding the 2015 environment for refining and petrochemicals margins; expectations regarding 2015 refinery turnarounds and future refinery operations; expectations regarding improvements in cash break-even performance, earnings potential and future plant events in the petrochemicals business; expectations regarding future safety performance and plans to enhance safety, cybersecurity, compliance and risk management; Air BP s strategic aims; the future strategy for and planned investments in alternative energies; the expected annual charges of Other business and corporate for 2015; expectations regarding the actions of contractors and partners and their terms of service; expectations regarding future environmental regulations, their impact on BP s business and plans to reduce BP s environmental impact; expectations regarding changes in laws and regulations and their impact on BP s business; plans to increase efficiency, reliability and product quality, improve margins and create new market opportunities; expectations regarding future Upstream operations, including agreements or contracts with or relating to TEPCO, BP s CATS business, Tangguh and CNOOC, BP s joint-ownership interests in exploration blocks and plans to drill therein; plans to transfer operatorship of certain fields, expectations of awards from award rounds; plans related to the Alaska LNG project and the Canadian oil sands; plans and expectations regarding the Point Thomson production facility, the Angola LNG plant, the exploration and production-sharing agreement in Libya, the North Damietta offshore concession, exploration in Morocco, exploration in India, the Sanga-Sanga CBM PSA, the Southern Gas Corridor, the Khazzan field, the Gorgon LNG plant and the Ceduna Sub Basin; expected expirations of concessions, contracts and exploration periods; projections regarding oil and gas reserves, including recovery and turnover time thereof; plans regarding compliance with ITRA rules, sanctions and reporting requirements, including in relation to BP s stake in the Rhum joint arrangement and future engagement in business with Iran; plans to take action under and comply with the EPA Administrative Agreement; plans with regard to the timing of and actions to be taken at the AGM, including amendments to the proposal of amendments to the Articles of Association; expectations regarding future restoration or other actions to be taken as a result of the Deepwater Horizon incident and related proceedings and their impact on BP s business; and expectations regarding legal and trial proceedings, court decisions, potential investigations and civil actions by regulators, government entities and/or other entities or parties, and the risks associated with such proceedings and BP s intentions in respect thereof; (2) certain statements in Corporate governance (pages 51-71) and the Directors remuneration report (pages 72-88) with regard to the anticipated future composition of the board of directors; the board s goals and areas of focus stemming from the board s annual evaluation; plans regarding and the timing of

future audit contract tendering and areas of focus for the audit committee; the expected percentage of performance shares that will vest based on performance outcomes; and plans and expectations with regard to the remuneration, pensions and other benefits of executive directors, including disclosure of targets, future review schedules, prospective scenarios for total remuneration opportunities for executive directors in the future, changes in the metrics used to calculate remuneration and changes to the limits of aggregate annual remuneration; and (3) certain statements in the Strategic report (inside front cover and pages 1-50) and Additional disclosures (pages 211-212), with regard to future dividend and optional scrip dividend payments; future capital expenditures and capital investment, including estimated 2015 levels thereof, 2015 taxation, future working capital and cash management, gearing and the net debt ratio; BP s intention to maintain a strong cash position; and expected payments under contractual and commercial commitments and purchase obligations; are all forward looking in nature.

By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of BP. Actual results may differ materially from those expressed in such statements, depending on a variety of factors, including: the specific factors identified in the discussions accompanying such forward-looking statements; the receipt of relevant third party and/or regulatory approvals; the timing and level of maintenance and/or turnaround activity; the timing and volume of refinery additions and outages; the timing of bringing new fields onstream; the timing, quantum and nature of certain divestments; future levels of industry product supply, demand and pricing, including supply growth in North America; OPEC quota restrictions; production-sharing agreements effects; operational and safety problems; potential lapses in product quality; economic and financial market conditions generally or in various countries and regions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; regulatory or legal actions including the types of enforcement action pursued and the nature of remedies sought or imposed; the actions of prosecutors, regulatory authorities and courts; the impact on our reputation following the Gulf of Mexico oil spill; the actions of the Claims Administrator appointed under the Economic and Property Damages Settlement; the actions of all parties to the Gulf of Mexico oil spill-related litigation at various phases of the litigation; the timing and amount of future payments relating to the Gulf of Mexico oil spill; exchange rate fluctuations; development and use of new technology; recruitment and retention of a skilled workforce; the success or otherwise of partnering; the actions of competitors, trading partners, contractors, subcontractors, creditors, rating agencies and others; our access to future credit resources; business disruption and crisis management; the impact on our reputation of ethical misconduct and non-compliance with regulatory obligations; trading losses; major uninsured losses; decisions by Rosneft s management and board of directors; the actions of contractors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism; cyber-attacks or sabotage; and other factors discussed elsewhere in this report including under Risk factors (pages 48-50). In addition to factors set forth elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Statements regarding competitive position

Statements referring to BP s competitive position are based on the company s belief and, in some cases, rely on a range of sources, including investment analysts reports, independent market studies and BP s internal assessments of market share based on publicly available information about the financial results and performance of market participants.

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Share prices and listings

Markets and market prices

The primary market for BP s ordinary shares is the London Stock Exchange (LSE). BP s ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index. BP s ordinary shares are also traded on the Frankfurt Stock Exchange in Germany.

Trading of BP s shares on the LSE is primarily through the use of the Stock Exchange Electronic Trading Service (SETS), introduced in 1997 for the largest companies in terms of market capitalization whose primary listing is the LSE. Under SETS, buy and sell orders at specific prices may be sent electronically to the exchange by any firm that is a member of the LSE, on behalf of a client or on behalf of itself acting as a principal. The orders are then anonymously displayed in the order book. When there is a match on a buy and a sell order, the trade is executed and automatically reported to the LSE. Trading is continuous from 8.00am to 4.30pm UK time but, in the event of a 20%

movement in the share price either way, the LSE may impose a temporary halt in the trading of that company s shares in the order book to allow the market to re-establish equilibrium. Dealings in ordinary shares may also take place between an investor and a market-maker, via a member firm, outside the electronic order book.

In the US, BP s securities are traded on the New York Stock Exchange (NYSE) in the form of ADSs, for which JPMorgan Chase Bank, N.A. is the depositary (the Depositary) and transfer agent. The Depositary s principal office is 4 New York Plaza, Floor 12, New York, NY, 10004, US. Each ADS represents six ordinary shares. ADSs are listed on the NYSE. ADSs are evidenced by American depositary receipts (ADRs), which may be issued in either certificated or book entry form.

The following table sets forth, for the periods indicated, the highest and lowest middle market quotations for BP s ordinary shares and ADSs for the periods shown. These are derived from the highest and lowest intra-day sales prices as reported on the LSE and NYSE, respectively.

	Pence		Dollars	
	Ordinary shares		American depositary shares[a]	
	High	Low	High	Low
Year ended 31 December				
2010	658.20	296.00	62.38	26.75
2011	514.90	361.25	49.50	33.62
2012	512.00	388.56	48.34	36.25
2013	494.20	426.50	48.65	39.99
2014	**526.80**	**364.40**	**53.48**	**34.88**
Year ended 31 December				
2013: First quarter	482.33	426.50	45.45	39.99
Second quarter	485.43	437.25	44.27	40.12
Third quarter	477.53	430.30	43.75	40.51
Fourth quarter	494.20	426.55	48.65	41.30
2014: First quarter	**510.00**	**462.64**	**51.02**	**45.83**
Second quarter	**526.80**	**467.10**	**53.48**	**47.14**

Third quarter	**525.80**	**440.72**	**53.48**	**43.80**
Fourth quarter	**455.45**	**364.40**	**44.14**	**34.88**
2015: First quarter (to 17 February)	**463.10**	**376.70**	**42.10**	**34.93**
Month of				
September 2014	**494.90**	**440.72**	**48.11**	**43.80**
October 2014	**455.45**	**405.35**	**44.14**	**39.45**
November 2014	**452.45**	**408.80**	**43.08**	**39.19**
December 2014	**439.80**	**364.40**	**41.59**	**34.88**
January 2015	**445.68**	**376.70**	**40.44**	**34.93**
February 2015 (to 17 February)	**463.10**	**426.35**	**42.10**	**39.19**

[a] One ADS is equivalent to six 25 cent ordinary shares.
Source: Thomson Reuters Datastream.

Market prices for the ordinary shares on the LSE and in after-hours trading off the LSE, in each case while the NYSE is open, and the market prices for ADSs on the NYSE, are closely related due to arbitrage among the various markets, although differences may exist from time to time.

On 17 February 2015, 883,647,170.5 ADSs (equivalent to approximately 5,301,883,023 ordinary shares or some 29.07% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 95,858 ADS holders. Of these, about 94,687 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 979,038 underlying holders.

On 17 February 2015, there were approximately 270,163 ordinary shareholders. Of these shareholders, around 1,570 had registered addresses in the US and held a total of some 4,005,034 ordinary shares.

Since a number of the ordinary shares and ADSs were held by brokers and other nominees, the number of holders in the US may not be representative of the number of beneficial holders of their respective country of residence.

Dividends

BP s current policy is to pay interim dividends on a quarterly basis on its ordinary shares.

Its policy is also to announce dividends for ordinary shares in US dollars and state an equivalent sterling dividend. Dividends on BP ordinary shares will be paid in sterling and on BP ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the market exchange rates in London over the four business days prior to the sterling equivalent announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced. It is not the company s intention to change its current policy of announcing dividends on ordinary shares in US dollars.

Information regarding dividends announced and paid by the company on ordinary shares and preference shares is provided in Financial statements Note 8.

A Scrip Dividend Programme (Scrip Programme) was approved by shareholders in 2010. It enables BP ordinary shareholders and ADS holders to elect to receive dividends by way of new fully paid BP ordinary shares (or ADSs in the case of ADS holders) instead of cash. The company intends to propose a resolution to the shareholders at the

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next AGM that the Scrip Programme be renewed for a further three years. The operation of the Scrip Programme is always subject to the directors decision to make the Scrip Programme offer available in respect of any particular dividend. Should the directors decide not to offer the Scrip Programme in respect of any particular dividend, cash will be paid automatically instead.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on page 48 and other matters that may affect the business of the group set out in Our strategy on page 13 and in Liquidity and capital resources on page 211.

The following table shows dividends announced and paid by the company per ADS for the past five years.

Dividends per ADS[a]		March	June	September	December	Total
2010	UK pence	52.07				52.07
	US cents	84				84
2011	UK pence	26.02	25.68	25.90	26.82	104.42
	US cents	42	42	42	42	168
2012	UK pence	30.57	30.90	30.10	33.53	125.10
	US cents	48	48	48	54	198
2013	UK pence	36.01	35.01	34.58	34.80	140.40
	US cents	54	54	54	57	219
2014	**UK pence**	**34.24**	**34.84**	**35.76**	**38.26**	**143.10**
	US cents	**57**	**58.5**	**58.5**	**60**	**234**

[a] Dividends announced and paid by the company on ordinary and preference shares are provided in Financial statements Note 8.

UK foreign exchange controls on dividends

There are currently no UK foreign exchange controls or restrictions on remittances of dividends on the ordinary shares or on the conduct of the company s operations, other than restrictions applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

There are no limitations, either under the laws of the UK or under the company s Articles of Association, restricting the right of non-resident or foreign owners to hold or vote BP ordinary or preference shares in the company other than limitations that would generally apply to all of the shareholders and limitations applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

Shareholder taxation information

This section describes the material US federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder who holds the ordinary shares or ADSs as capital assets for tax purposes. It does not apply, however, interalia to members of special classes of holders some of which may be subject to other rules, including: tax-exempt entities, life insurance companies, dealers in securities, traders in securities that elect a mark-to-market method of accounting for securities holdings, investors liable for alternative minimum tax, holders that, directly or indirectly, hold 10% or more of the company s voting stock, holders that hold the shares or ADSs as part of a straddle or a hedging or conversion transaction, holders that purchase or sell the shares or ADSs as part of a wash sale for US federal income tax purposes, or holders whose functional currency is not the US dollar. In addition, if a partnership holds the shares or ADSs, the US federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership and may not be described fully below.

A US holder is any beneficial owner of ordinary shares or ADSs that is for US federal income tax purposes (i) a citizen or resident of the US, (ii) a US domestic corporation, (iii) an estate whose income is subject to US federal income taxation regardless of its source, or (iv) a trust if a US court can exercise primary supervision over the trust s administration and one or more US persons are authorized to control all substantial decisions of the trust.

This section is based on the tax laws of the United States, including the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed US Treasury regulations thereunder, published rulings and court decisions, and the taxation laws of the UK, all as currently in effect, as well as the income tax convention between the US and the UK that entered into force on 31 March 2003 (the Treaty). These laws are subject to change, possibly on a retroactive basis. This section further assumes that each obligation in the Deposit Agreement and any related agreement will be performed in accordance with its terms.

For purposes of the Treaty and the estate and gift tax Convention (the Estate Tax Convention) and for US federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the company s ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs and ADRs for ordinary shares generally will not be subject to US federal income tax or to UK taxation other than stamp duty or stamp duty reserve tax, as described below.

Investors should consult their own tax adviser regarding the US federal, state and local, UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Treaty in respect of their investment in the shares or ADSs.

Taxation of dividends

UK taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the company, including dividends paid to US holders. A shareholder that is a company resident for tax purposes in the UK or trading in the UK through a permanent establishment generally will not be taxable in the UK on a dividend it receives from the company. A shareholder who is an individual resident for tax purposes in the UK is subject to UK tax but entitled to a tax credit on cash dividends paid on ordinary shares or ADSs of the company equal to one-ninth of the cash dividend.

US federal income taxation

A US holder is subject to US federal income taxation on the gross amount of any dividend paid by the company out of its current or accumulated earnings and profits (as determined for US federal income tax purposes). Dividends paid to a non-corporate US holder that constitute qualified dividend income will be taxable to the holder at a preferential rate, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the company with respect to the ordinary shares or ADSs will generally be qualified dividend income.

As noted above in UK taxation, a US holder will not be subject to UK withholding tax. Accordingly, a US holder will include only the dividend actually received from the company in gross income for US federal income tax purposes, and the receipt of a dividend will not entitle the US holder to a foreign tax credit.

For US federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depositary, in the case of ADSs, actually or constructively receives the dividend and will not be eligible for the dividends-received deduction generally allowed to US corporations in respect of dividends received from other US corporations. Dividends will be income from sources outside the US and generally will be passive category income or, in the case of certain US holders, general category income , each of which is treated separately for purposes of computing a US holder s foreign tax credit limitation.

The amount of the dividend distribution on the ordinary shares that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/US dollar rate on the date the dividend distribution is includible in income, regardless of whether the payment is, in fact, converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is includible in income to the date the payment is converted into US dollars will be treated as ordinary income or loss and will not be eligible for the preferential tax rate on qualified dividend income. The gain or loss generally will be income or loss from sources within the US for foreign tax credit limitation purposes.

Distributions in excess of the company s earnings and profits, as determined for US federal income tax purposes, will be treated as a return of capital to the extent of the US holder s basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described in Taxation of capital gains US federal income taxation section below.

In addition, the taxation of dividends may be subject to the rules for passive foreign investment companies (PFIC), described below under Taxation of capital gains US federal income taxation . Distributions made by a PFIC do not constitute qualified dividend income and are not eligible for the preferential tax rate applicable to such income.

Taxation of capital gains

UK taxation

A US holder may be liable for both UK and US tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (i) a citizen of the US resident or ordinarily resident in the UK, (ii) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK or (iii) a citizen of the US that carries on a trade or profession or vocation in the UK through a branch or agency or a corporation that carries on a trade, profession or vocation in the UK, through a permanent establishment, and that has used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment. However, such persons may be entitled to a tax credit against their US federal income tax liability for the amount of UK capital gains tax or UK corporation tax on chargeable gains (as the case may be) that is paid in respect of such gain.

Under the Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence of the relevant holder as determined under both the laws of the UK and the US and as required by the terms of the Treaty.

Under the Treaty, individuals who are residents of either the UK or the US and who have been residents of the other jurisdiction (the US or the UK, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the company not only in the jurisdiction of which the holder is resident at the time of the disposition but also in the other jurisdiction.

US federal income taxation

A US holder who sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for US federal income tax purposes equal to the difference between the US dollar value of the amount realized on the disposition and the US holder s tax basis, determined in US dollars, in the ordinary shares or ADSs. Any such capital gain or loss generally will be long-term gain or loss, subject to tax at a preferential rate for a non-corporate US holder, if the US holder s holding period for such ordinary shares or ADSs exceeds one year.

Gain or loss from the sale or other disposition of ordinary shares or ADSs will generally be income or loss from sources within the US for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

We do not believe that ordinary shares or ADSs will be treated as stock of a passive foreign investment company, or PFIC, for US federal income tax purposes, but this conclusion is a factual determination that is made annually and thus is subject to change. If we are treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to ordinary shares or ADSs, any gain realized on the sale or other disposition of ordinary shares or ADSs would in general not be treated as capital gain. Instead, a US holder would be treated as if he or she had realized such gain rateably over the holding period for ordinary shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, in addition to which an interest charge in respect of the tax attributable to each such year would apply. Certain excess distributions would be similarly treated if we were treated as a PFIC.

Additional tax considerations

Scrip Dividend Programme

The company has an optional Scrip Programme, wherein holders of BP ordinary shares or ADSs may elect to receive any dividends in the form of new fully paid ordinary shares or ADSs of the company instead of cash. Please consult your tax adviser for the consequences to you.

UK inheritance tax

The Estate Tax Convention applies to inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to UK inheritance tax on the individual s death or on transfer during the individual s lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK used for the performance of independent personal services. In the exceptional case where ADSs are subject to both inheritance tax and US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

UK stamp duty and stamp duty reserve tax

The statements below relate to what is understood to be the current practice of HM Revenue & Customs in the UK under existing law.

Provided that any instrument of transfer is not executed in the UK and remains at all times outside the UK and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of £5 per £1,000 (or part, unless the stamp duty is less than £5, when no stamp duty is charged), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser.

A subsequent transfer of ordinary shares to the Depositary s nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer. For ADR holders electing to receive ADSs instead of cash, after the 2012 first quarter dividend payment HM Revenue & Customs no longer seeks to impose 1.5% stamp duty reserve tax on issues of UK shares and securities to non-EU clearance services and depositary receipt systems.

US Medicare Tax

A US holder that is an individual or estate, or a trust that does not fall into a special class of trusts that is exempt from such tax, is subject to a 3.8% tax on the lesser of (1) the US holder s net investment income (or undistributed net investment income in the case of an estate or trust) for the relevant taxable year and (2) the excess of the US holder s modified adjusted gross income for the taxable year over a certain threshold (which in the case of individuals is between $125,000 and $250,000, depending on the individual s circumstances). A holder s net investment income generally includes its dividend income and its net gains from the disposition of shares or ADSs, unless such dividend income or net gains are derived in the ordinary course of the conduct of a trade or business (other than a trade or business that consists of certain passive or trading activities). If you are a US holder that is an individual, estate or trust, you are urged to consult your tax advisors regarding the applicability of the Medicare tax to your income and gains in respect of your investment in the shares or ADSs.

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Major shareholders

The disclosure of certain major and significant shareholdings in the share capital of the company is governed by the Companies Act 2006, the UK Financial Conduct Authority s Disclosure and Transparency Rules (DTR) and the US Securities Exchange Act of 1934.

Register of members holding BP ordinary shares as at 31 December 2014

Range of holdings	Number of ordinary shareholders	Percentage of total ordinary shareholders	Percentage of total ordinary share capital excluding shares held in treasury
1-200	56,090	20.67	0.02
201-1,000	95,613	35.24	0.28
1,001-10,000	107,541	39.63	1.79
10,001-100,000	10,659	3.93	1.18
100,001-1,000,000	773	0.29	1.59
Over 1,000,000[a]	659	0.24	95.14
Totals	271,335	100.00	100.00

[a] Includes JPMorgan Chase Bank, N.A. holding 28.79% of the total ordinary issued share capital (excluding shares held in treasury) as the approved depositary for ADSs, a breakdown of which is shown in the table below.

Register of holders of American depositary shares (ADSs) as at 31 December 2014[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	55,981	58.01	0.35
201-1,000	25,960	26.90	1.42
1,001-10,000	13,816	14.32	4.14
10,001-100,000	740	0.77	1.42
100,001-1,000,000	8	0.00	0.13
Over 1,000,000[b]	1	0.00	92.54
Totals	96,506	100.00	100.00

[a] One ADS represents six 25 cent ordinary shares.

[b] One holder of ADSs represents 979,038 underlying shareholders.

As at 31 December 2014, there were also 1,483 preference shareholders. Preference shareholders represented 0.46% and ordinary shareholders represented 99.54% of the total issued nominal share capital of the company (excluding shares held in treasury) as at that date.

In accordance with DTR 5, we have received notification that as at 31 December 2014 BlackRock, Inc held 5.91%, The Capital Group Companies, Inc held 3.31% and Legal & General Group plc held 3.21% of the voting rights of the issued share capital of the company. As at 17 February 2015 BlackRock, Inc held 6.25%, The Capital Group Companies, Inc held 3.51% and Legal & General Group plc held 3.27% of the voting rights of the issued share capital of the company.

Under the US Securities Exchange Act of 1934 BP has received notification of the following interests as at 17 February 2015:

Holder	Holding of ordinary shares	Percentage of ordinary share capital excluding shares held in treasury
JPMorgan Chase Bank N.A., depositary for ADSs, through its nominee Guaranty Nominees Limited	5,301,883,023	29.07
BlackRock, Inc.	1,139,520,000	6.25

The company s major shareholders do not have different voting rights.

The company has also been notified of the following interests in preference shares as at 17 February 2015:

Holder	Holding of 8% cumulative first preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society	945,000	13.07
M & G Investment Management Ltd.	528,150	7.30
Duncan Lawrie Ltd.	364,876	5.04

Holder	Holding of 9% cumulative second preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society	987,000	18.03
M & G Investment Management Ltd.	644,450	11.77
Smith & Williamson Investment Management Ltd.	333,200	6.09
Bank Julius Baer	294,000	5.37
Barclays Bank PLC.	279,172	5.10

In accordance with DTR 5.8.12, The Capital Group of Companies, Inc. notified the company on 24 September 2012 that due to their group reorganization their holdings would not be reported separately but as combined holdings, thereby taking their interest in shares above the 3% threshold as of 1 September 2012.

Smith and Williamson Holdings Limited disposed of its interest in 32,500 8% cumulative first preference shares during 2014.

In accordance with DTR 5.6, BlackRock, Inc. notified the company that its indirect interest in ordinary shares decreased below 5% during 2014.

UBS Investment Bank notified the company that its indirect interest in ordinary shares increased above 3% on 9 February 2015 and that it decreased below the notifiable threshold on 16 February 2015.

As at 17 February 2015, the total preference shares in issue comprised only 0.46% of the company s total issued nominal share capital (excluding shares held in treasury), the rest being ordinary shares.

Annual general meeting

The 2015 AGM will be held on Thursday 16 April 2015 at 11.30am at ExCeL London, One Western Gateway, Royal Victoria Dock, London, E16 1XL. A separate notice convening the meeting is distributed to shareholders, which includes an explanation of the items of business to be considered at the meeting.

All resolutions for which notice has been given will be decided on a poll. Ernst & Young LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in the *Notice of BP Annual General Meeting 2015*.

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 (the 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 251.

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. New Articles of Association are being proposed at our AGM in 2015.

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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.

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 (Scrip Programme) and to include provisions in the Articles of Association to enable the company to operate the Scrip Programme. The Scrip 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 Scrip 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 on 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 quarters of the persons voting at a meeting at which there is a quorum.

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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 (1) the capital paid up on such shares plus, (2) accrued and unpaid dividends and (3) a premium equal to the higher of (a) 10% of the capital paid up on the BP preference shares and (b) the excess of the average market price over par value of such shares on the LSE during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, BP may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolutions, by determination of the directors), and may issue shares that are to be or may be redeemed.

Variation of rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or on the adoption of a special resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the Articles of Association relating to proceedings at a general meeting apply, except that the quorum with respect to a meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one third or more of the shares of that class.

Shareholders meetings and notices

Shareholders must provide BP with a postal or electronic address in the UK to be entitled to receive notice of shareholders meetings. Holders of BP ADSs are entitled to receive notices under the terms of the deposit agreement relating to BP ADSs. The substance and timing of notices are described on page 248 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 in 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, either under the laws of the UK or under the company s Articles of Association, restricting the right of non-resident or foreign owners to hold or vote BP ordinary or preference shares in the company other than limitations that would generally apply to all of the shareholders and limitations applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

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.

Called-up share capital

Details of the allotted, called-up and fully-paid share capital at 31 December 2014 are set out in Financial statements Note 29.

At the AGM on 10 April 2014, authorization was given to the directors to allot shares up to an aggregate nominal amount equal to $3,076 million. Authority was also given to the directors to allot shares for cash and to dispose of treasury shares, other than by way of rights issue, up to a maximum of $231 million, without having to offer such shares to existing shareholders. These authorities were given for the period until the next AGM in 2015 or 10 July 2015, whichever is the earlier. These authorities are renewed annually at the AGM.

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Purchases of equity securities by the issuer and affiliated purchasers

In March 2013 BP began a share repurchase, or buyback, programme (the buyback programme) with an expected total value of up to $8 billion. The decision to buy back shares followed the completion of the sale of BP s 50% interest in TNK-BP to Rosneft. The programme expected to return to BP shareholders an amount equivalent to the value of BP s original investment in TNK-BP and to exceed that required to offset the earnings per share dilution expected as a result of the sale of TNK-BP. It also reflected the reduction in BP s asset base following its $38-billion divestment programme. The buyback programme was completed in July 2014.

A further $2.3 billion of share repurchases were carried out in 2014 after the completion of the previously announced programme, funded by BP s continuing divestment of assets as announced in October 2013, and under the authority granted by shareholders at the 2014 AGM for BP to repurchase up to 1.8 billion ordinary shares.

The following table provides details of share repurchase, or buyback, activity as well as details of ordinary share purchases made by the Employee Share Ownership Plans (ESOPs) and other purchases of ordinary shares and ADSs made to satisfy the requirements of certain employee share-based payment plans.

	Total number of shares purchased[a]	**Average price paid per share $**	Number of shares purchased by ESOPs or for certain employee share-based payment plans[b]	Number of shares purchased as part of the programme[c]	Maximum approximate dollar value of shares yet to be purchased under the programme $ million
2014					
January 2 January 31	**162,240,000**	**8.09**		162,240,000	1,194
February 3 February 28	**48,436,545**	**8.06**	2,000,000	46,436,545	819
March 3 March 31	**36,410,000**	**8.03**		36,410,000	527
April 1 April 30	**17,980,000**	**8.16**		17,980,000	380
May 1 May 30	**17,386,000**	**8.54**		17,386,000	232
June 2 June 30	**18,082,500**	**8.68**		18,082,500	75
July 1 July 31	**23,927,485**	**8.57**		23,927,485	
August 1 August 29	**70,519,200**	**8.05**	8,300,000	62,219,200	
September 1 September 30	**123,054,453**	**7.66**		123,054,453	
October 1 October 31	**75,398,500**	**7.02**		75,398,500	
November 3 November 7	**8,029,320**	**7.02**		8,029,320	
December 2 December 22	**51,149,002**	**6.28**	30,400,000	20,749,002	
2015					
January 9 January 30	**31,600,000**	**6.27**	31,600,000		
February 2 to February 5	**6,960,000**	**6.50**	6,960,000		

[a] All share purchases were of ordinary shares of 25 cents each and/or ADSs (each representing six ordinary shares) and were on/open market transactions.

[b] Transactions represent the purchase of ordinary shares by ESOPs and other purchases of ordinary shares and ADSs made to satisfy requirements of certain employee share-based payment plans.

[c] At the AGMs on 11 April 2013 and 10 April 2014, authorization was given to the company to repurchase up to 1.9 billion and 1.8 billion ordinary shares, respectively, for the periods until the next AGM in 2014 and 2015 or 11 July 2014 and 10 July 2015 respectively, being the latest dates by which an AGM must be held for the relevant year. This authorization is renewed annually at the AGM. The total number of ordinary shares repurchased during 2014 was 611,913,005 at a cost of $4,796 million (including transaction costs) representing 3.36% of BP s issued share capital excluding shares held in treasury on 31 December 2014. All ordinary shares repurchased in 2013 and 2014 were cancelled in order to reduce BP s issued share capital.

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Fees and charges payable by ADSs holders

The Depositary collects fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of the distributable property to pay the fees.

The charges of the Depositary payable by investors are as follows:

Type of service	Depositary actions	Fee
Depositing or substituting the underlying shares	Issuance of ADSs against the deposit of shares, including deposits and issuances in respect of: Share distributions, stock splits, rights, merger. Exchange of securities or other transactions or event or other distribution affecting the ADSs or deposited securities.	$5.00 per 100 ADSs (or portion thereof) evidenced by the new ADSs delivered.
Selling or exercising rights	Distribution or sale of securities, the fee being an amount equal to the fee for the execution and delivery of ADSs that would have been charged as a result of the deposit of such securities.	$5.00 per 100 ADSs (or portion thereof).
Withdrawing an underlying share	Acceptance of ADSs surrendered for withdrawal of deposited securities.	$5.00 for each 100 ADSs (or portion thereof) evidenced by the ADSs surrendered.
Expenses of the Depositary	Expenses incurred on behalf of holders in connection with: Stock transfer or other taxes and governmental charges. Delivery by cable, telex, electronic and facsimile transmission. Transfer or registration fees, if applicable, for the registration of transfers of underlying shares. Expenses of the Depositary in connection with the conversion of foreign currency into US dollars (which are paid out of such foreign currency).	Expenses payable are subject to agreement between the company and the Depositary by billing holders or by deducting charges from one or more cash dividends or other cash distributions.

Fees and payments made by the Depositary to the issuer

The Depositary has agreed to reimburse certain company expenses related to the company s ADS programme and incurred by the company in connection with the ADS programme arising during the year ended 31 December 2014. The Depositary reimbursed to the company, or paid amounts on the company s behalf to third parties, or waived its fees and expenses, of $3,612,749.32 for the year ended 31 December 2014.

The table below sets out the types of expenses that the Depositary has agreed to reimburse and the fees it has agreed to waive for standard costs associated with the administration of the ADS programme relating to the year ended 31 December 2014. The Depositary has also paid certain expenses directly to third parties on behalf of the company.

Category of expense reimbursed, waived or paid directly to third parties	Amount reimbursed, waived or paid directly to third parties for the year ended 31 December 2014 $
NYSE listing fees reimbursed	400,000.00
Service fees and out of pocket expenses waived[a]	2,223,141.13
Broker fees reimbursed[b]	901,224.03
Other third-party mailing costs reimbursed[c]	88,384.16
Total	3,612,749.32

[a] Includes fees in relation to transfer agent costs and costs of the BP Scrip Dividend Programme operated by JPMorgan Chase Bank, N.A.

[b] Broker reimbursements are fees payable to Broadridge for the distribution of hard copy material to ADR beneficial holders in the Depository Trust Company. Corporate materials include information related to shareholders meetings and related voting instructions. These fees are SEC approved.

[c] Payment of fees to Precision IR for investor support.

Under certain circumstances, including removal of the Depositary or termination of the ADR programme by the company, the company is required to repay the Depositary amounts reimbursed and/or expenses paid to or on behalf of the company during the 12-month period prior to notice of removal or termination.

Documents on display

BP Annual Report and Form 20-F 2014 and *BP Strategic Report 2014* are available online at *bp.com/annualreport*. To obtain a hard copy of BP s complete audited financial statements, free of charge, UK based shareholders should contact BP Distribution Services by calling +44 (0)870 241 3269 or by emailing *bpdistributionservices@bp.com*. If based in the US or Canada shareholders should contact Issuer Direct by calling +1 888 301 2505 or by emailing *bpreports@precisionir.com.*

The company is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, the company files its Annual Report and Form 20-F and other related documents with the SEC. It is possible to read and copy documents that have been filed with the SEC at its headquarters located at 100 F Street, NE, Washington, DC 20549, US. You may also call the SEC at +1 800-SEC-0330. In addition, BP s SEC filings are available to the public at the SEC s website. BP discloses on its website at *bp.com/NYSEcorporategovernancerules* and in this report (see Corporate governance practices (Form 20-F Item 16G) on page 239) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

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Shareholding administration

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payments, the Scrip Programme or to change the way you receive your company documents (such as the *BP Annual Report and Form 20-F, BP Strategic Report* and *Notice of BP Annual General Meeting*) please contact the BP Registrar or the BP ADS Depositary.

Ordinary and preference shareholders

The BP Registrar

Capita Asset Services

The Registry, 34 Beckenham Road

Beckenham, Kent BR3 4TU, UK

Freephone in UK 0800 701107

From outside the UK +44 (0)20 3170 3678

Fax +44 (0)1484 601512

ADS holders

JPMorgan Chase Bank, N.A. PO Box 64504

St Paul, MN 55164-0504, US

Toll-free in US and Canada +1 877 638 5672

From outside the US and Canada +1 651 306 4383

Exhibits

The following documents are filed in the Securities and Exchange Commission (SEC) EDGAR system, as part of this Annual Report on Form 20-F, and can be viewed on the SEC s website.

Exhibit 1	Memorandum and Articles of Association of BP p.l.c.*
Exhibit 4.1	The BP Executive Directors Incentive Plan
Exhibit 4.2	Amended BP Deferred Annual Bonus Plan 2005**
Exhibit 4.3	Amended Director s Secondment Agreement for R W Dudley******
Exhibit 4.4	Amended Director s Service Contract and Secondment Agreement for R W Dudley*
Exhibit 4.6	Director s Service Contract for I C Conn***
Exhibit 4.7	Director s Service Contract for Dr B Gilvary****
Exhibit 7	Computation of Ratio of Earnings to Fixed Charges (Unaudited)

Exhibit 8	Subsidiaries (included as Note 35 to the Financial Statements)
Exhibit 10.1	Administrative Agreement dated as of 13 March 2014 among the US Environmental Protection Agency, BP p.l.c., and other BP subsidiaries
Exhibit 11	Code of Ethics*****
Exhibit 12	Rule 13a 14(a) Certifications
Exhibit 13	Rule 13a 14(b) Certifications#
Exhibit 15.1	Consent of DeGolyer and MacNaughton
Exhibit 15.2	Report of DeGolyer and MacNaughton

* Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2010.

** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2012.

*** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2004.

**** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2011.

***** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2009.

****** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2013.

\# Furnished only.

Included only in the annual report filed in the Securities and Exchange Commission EDGAR system.

The total amount of long-term securities of the Registrant and its subsidiaries authorized under any one instrument does not exceed 10% of the total assets of BP p.l.c. and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any or all such instruments to the SEC on request.

Abbreviations, glossary and trade marks

ADR

American depositary receipt.

ADS

American depositary share. 1 ADS = 6 ordinary shares.

Barrel (bbl)

159 litres, 42 US gallons.

bcf/d

Billion cubic feet per day.

bcfe

Billion cubic feet equivalent.

bcma

Billion cubic metres per annum.

b/d

Barrels per day.

boe/d

Barrels of oil equivalent per day.

DoJ

US Department of Justice.

GAAP

Generally accepted accounting practice.

Gas

Natural gas.

GWh

Gigawatts per hour.

IFRS

International Financial Reporting Standards.

KPIs

Key performance indicators.

LNG

Liquefied natural gas.

LPG

Liquefied petroleum gas.

mb/d

Thousand barrels per day.

mboe/d

Thousand barrels of oil equivalent per day.

mmb/d

Million barrels per day.

mmboe/d

Million barrels of oil equivalent per day.

mmBtu

Million British thermal units.

mmcf/d

Million cubic feet per day.

mmte

Million tonnes.

MWh

Megawatt per hour.

NGLs

Natural gas liquids.

PSA

Production-sharing agreement.

PTA

Purified terephthalic acid.

RC

Replacement cost.

SEC

The United States Securities and Exchange Commission.

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Glossary

Unless the context indicates otherwise, the definitions for the following glossary terms are given below.

Associate

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

Consolidation adjustment UPII

Unrealized profit in inventory arising on inter-segment transactions.

Commodity trading contracts

BP s Upstream and Downstream segments both participate in regional and global commodity trading markets in order to manage, transact and hedge the crude oil, refined products and natural gas that the group either produces or consumes in its manufacturing operations. These physical trading activities, together with associated incremental trading opportunities, are discussed in Upstream on page 28 and in Downstream on page 31. The range of contracts the group enters into in its commodity trading operations is described below. Using these contracts, in combination with rights to access storage and transportation capacity, allows the group to access advantageous pricing differences between locations, time periods and arbitrage between markets.

Exchange-traded commodity derivatives

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

Over-the-counter contracts

Contracts that are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties or through brokers, others may be cleared by a central clearing counterparty. These contracts can be used both for trading and risk management activities. Realized and unrealized gains and losses on over-the-counter (OTC) contracts are included in sales and other operating revenues for accounting purposes. Many grades of crude oil bought and sold use standard contracts including US domestic light sweet crude oil, commonly referred to as West Texas Intermediate, and a standard North Sea crude blend Brent, Forties, Oseberg and Ekofisk (BFOE). Forward contracts are used in connection with the purchase of crude oil supplies for refineries, products for marketing and sales of the group s oil production and refined products. The contracts typically contain standard delivery and settlement terms. These transactions call for physical delivery of oil with consequent operational and price risk. However, various means exist and are used from time to time, to settle obligations under the contracts in cash rather than through physical delivery. Because the physically settled transactions are delivered by cargo, the BFOE contract additionally specifies a standard volume and tolerance.

Gas and power OTC markets are highly developed in North America and the UK, where commodities can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price, with delivery and settlement at a future date. Typically, the contracts specify delivery terms for the underlying commodity. Some of these transactions are not settled physically as they can be achieved by transacting offsetting sale or purchase contracts for the same location and delivery period that are offset during the scheduling of delivery or dispatch. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically, volume, price and term (e.g. daily, monthly and balance of month) are the main variable contract terms.

Swaps are often contractual obligations to exchange cash flows between two parties. A typical swap transaction usually references a floating price and a fixed price with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell crude, oil products, natural gas or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry. Typically, netting agreements are used to limit credit exposure and support liquidity.

Spot and term contracts

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

Dividend yield

Sum of the four quarterly dividends declared in the year as a percentage of the year-end share price on the respective exchange.

Fair value accounting effects

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

BP enters into commodity contracts to meet certain business requirements, such as the purchase of crude for a refinery or the sale of BP s gas production. Under IFRS these contracts are treated as derivatives and are required to be fair valued when they are managed as part of a larger portfolio of similar transactions. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

IFRS require that inventory held for trading is recorded at its fair value using period-end spot prices, whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices, resulting in measurement differences. BP enters into contracts for pipelines and storage capacity, oil and gas processing and liquefied natural gas (LNG) that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments that are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference for consolidated entities by comparing the IFRS result with management s internal measure of performance. Under management s internal measure of performance the inventory and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period. The fair values of certain derivative instruments used to risk manage LNG and oil and gas processing contracts are deferred to match with the underlying exposure and the commodity contracts for business requirements are accounted for on an accruals basis. We believe that disclosing management s estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole.

Free cash flow

Operating cash flow less net cash used in investing activities, as presented in the condensed group cash flow statement.

Gearing

See Net debt and net debt ratio definition.

Hydrocarbons

Liquids and natural gas. Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Inventory holding gains and losses

The difference between the cost of sales calculated using the replacement cost of inventory 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 historical 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 based on the replacement cost of inventory. For this purpose, the replacement cost of inventory is calculated using data from each operation s production and manufacturing system, either on a monthly basis, or separately for each transaction where the system allows this approach. 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. See Replacement cost (RC) profit or loss definition below.

Joint arrangement

An arrangement in which two or more parties have joint control.

Joint control

Contractually agreed sharing of control over an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Joint operation

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.

Joint venture

A joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement.

Liquids

Comprises crude oil, condensate and natural gas liquids. For reserves, it also includes bitumen.

Major projects

Have a BP net investment of at least $250 million, or are considered to be of strategic importance to BP or of a high degree of complexity.

Net debt and net debt ratio (gearing)

Non-GAAP measures. Net debt includes the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is claimed. The derivatives are reported on the balance sheet within the headings Derivative financial instruments . We believe that net debt and net debt ratio 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 net debt ratio is defined as the ratio of finance debt (borrowings, including the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, plus obligations under finance leases) to the

total of finance debt plus shareholders interest. See Financial statements Note 25 for information on gross debt, which is the nearest equivalent measure to net debt on an IFRS basis.

Net wind generation capacity

The sum of the rated capacities of the assets/turbines that have entered into commercial operation, including BP s share of equity-accounted entities. The gross data is the equivalent capacity on a gross-JV basis, which includes 100% of the capacity of equity-accounted entities where BP has partial ownership.

Non-operating items

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 better to understand and evaluate the group s reported financial performance.

Operating capital employed

Non-GAAP measure. Total assets (excluding goodwill) less total liabilities, excluding finance debt and current and deferred taxation.

Operating cash flow and operating cash

Net cash provided by (used in) operating activities as stated in the condensed group cash flow statement. When used in the context of a segment rather than the group, the terms refer to the segment s share thereof.

Operating management system (OMS)

BP s OMS helps us manage risks in our operating activities by setting out BP s principles for good operating practice. It brings together BP requirements on health, safety, security, the environment, social responsibility and operational reliability, as well as related issues, such as maintenance, contractor relations and organizational learning, into a common management system.

Organic capital expenditure

Excludes acquisitions, asset exchanges, and other inorganic capital expenditure. An analysis of capital expenditure by segment and region is shown in Financial statements Note 4.

Plant efficiency

Plant efficiency is calculated taking 100% less the ratio of total plant deferrals divided by installed production capacity. Plant deferrals include planned and unplanned deferrals associated with the topside plant and where applicable the subsea equipment (excluding wells and reservoir). Plant deferrals include breakdowns, planned events, turnarounds, and weather.

Production-sharing agreement (PSA)

An arrangement through which an oil company bears the risks and costs of exploration, development and production. In return, if exploration is successful, the oil company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of the production remaining after such cost recovery.

Proved reserves replacement ratio

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.

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 downtime.

Refining marker margin (RMM)

The average of regional indicator margins weighted for BP s crude refining capacity in each region. Each regional marker margin is based on product yields and a marker crude oil deemed appropriate for the region. The regional indicator margins may not be representative of the margins achieved by BP in any period because of BP s particular refinery configurations and crude and product slate.

Replacement cost (RC) profit or loss

Reflects the replacement cost of inventories sold in the period 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 that is required to be disclosed for each operating segment under International Financial Reporting Standards (IFRS). RC profit or loss for the group is not a recognized GAAP measure. Management believes this measure is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due to changes in prices as well as changes in underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, BP s management believes it is helpful to disclose this measure. See Financial statements Note 4.

Subsidiary

An entity that is controlled by the BP group. Control of an investee exists when an 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.

Tier 1 process safety events

Losses 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.

Tight gas

Natural gas reservoirs locked in hard sandstone rocks with low permeability, making the underground formation extremely tight.

Underlying production

2014 underlying production, when compared with 2013, is after adjusting for the effects of the Abu Dhabi onshore concession expiry in January 2014, divestments and entitlement impacts in our production- sharing agreements.

2015 underlying production, when comparing with 2014, is after adjusting for divestments and entitlement impacts in our production-sharing agreements.

Underlying RC profit or loss

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. See pages 209 and 210 for additional information on the non-operating items and fair value accounting effects that are used to arrive at underlying RC profit or loss in order to enable a full understanding of the events and their financial impact. BP believes that underlying RC profit or loss is a useful measure for investors because it is a measure closely tracked by management to evaluate BP s operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in BP s operational performance on a comparable basis, year on year, by adjusting for the effects of these non-operating items and fair value accounting effects. The nearest equivalent measure on an IFRS basis for the group is profit or loss for the year attributable to BP shareholders. The nearest equivalent measure on an IFRS basis for segments is RC profit or loss before interest and taxation.

Unit cash margin

Net cash provided by operating activities for relevant projects in the Upstream segment, divided by the total number of barrels of oil and gas equivalent produced for the relevant projects. It excludes dividends and production for TNK-BP and Rosneft.

Trade marks

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

They include:

Aral

ARCO

BP

Castrol

EDGE

Field of the Future

Fluid Strength Technology

Titanium Fluid Strength Technology

SaaBre

Wild Bean Cafe

Permasense is a trade mark of Permasense Limited.

M&S Simply Food is a registered trade mark of Marks & Spencer plc.

The Directors report on pages 51-71, 90, 167-196 and 207-255 was approved by the board and signed on its behalf by David J Jackson, company secretary on 3 March 2015.

BP p.l.c.

Registered in England and Wales No. 102498

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Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.

(Registrant)

/s/ David J Jackson

Company secretary

3 March 2015

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Cross reference to Form 20-F

Table of Contents

BP s corporate reporting suite includes information about our financial and operating performance, sustainability performance and also on global energy trends and projections.

Annual Report and Form 20-F 2014
Details of our financial and operating performance in print or online.
Published in March.
bp.com/annualreport

Strategic Report 2014
A summary of our financial and operating performance in print or online.
Published in March.
bp.com/annualreport

Energy Outlook 2035
Projections for world energy markets, considering the potential evolution of global economy, population, policy and technology.
Published in February.
bp.com/energyoutlook

Sustainability Report 2014
Details of our sustainability performance with additional information online.
Published in March.
bp.com/sustainability

Financial and Operating Information 2010-2014
Five-year financial and operating data in PDF or Excel format.
Published in April.
bp.com/financialandoperating

Statistical Review of World Energy 2015
An objective review of key global energy trends.
Published in June.
bp.com/statisticalreview

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Paper

This document is printed on Oxygen paper and board. Oxygen is made using 100% recycled pulp, a large percentage of which is de-inked. It is manufactured at a mill with ISO 9001 and 14001 accreditation and is FSC® (Forest Stewardship Council) certified. This document has been printed using vegetable inks.

Printed in the UK by Pureprint Group using their *alco***free**® and *pure***print**® printing technology.