BP PLC
Form 20-F
March 04, 2016
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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 2015

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 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
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**
3.062% 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**
3.506% Guaranteed Notes due 2025	**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	20,108,770,973
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 x No ¨

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ¨ No 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 2015

bp.com/annualreport

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Who we are

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.

BP is one of the world s leading integrated oil and gas companies based on market capitalization, proved reserves and production. 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.

We believe a mix of fuels and technologies is needed to meet growing energy demand, improve efficiency and support the transition to a lower-carbon economy. These are the reasons why our portfolio includes oil, gas and renewables.

Our projects and operations help to generate employment, investment and tax revenues in countries and communities across the world. We have well-established operations in Europe, North and South America, Australasia, Asia and Africa and employ around 80,000 people.

Our proposition for value growth

For BP good business starts with a relentless focus on safe and reliable operations. Our portfolio enables us to develop high-quality opportunities from a broad set of options. We prioritize value over volume and invest where we can apply our distinctive strengths, capabilities and technologies.

Our objective is to create shareholder value by growing sustainable free cash flow and distributions over the long term through capital and cost discipline.

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Front cover images

In Oman s remote desert, we use our advanced technology to unlock gas from hot sandstone almost three miles below the earth s surface. Construction work has started on the Khazzan field one of the Middle East s largest unconventional gas resources and we expect first gas in late 2017.

Your feedback

We welcome your comments and feedback on our reporting. You can provide this at *bp.com/annualreportfeedback* or by emailing the corporate reporting team details are on the back cover.

Your views are important to us and help shape our reporting for future years.

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BP in 2015

It is a challenging time for our industry but we are making the changes that are needed without compromising our longer-term goals.

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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 2015. A cross reference to Form 20-F requirements is included on page 260.

This document contains the Strategic report on pages 1-54 and the inside cover (Who we are) and the Directors report on pages 55-75, 169-195 and 215-258. 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 22-23 and 76-92. The consolidated financial statements of the group are on pages 95-168 and the corresponding reports of the auditor are on pages 101-102.

BP Annual Report and Form 20-F 2015 and *BP Strategic Report 2015* (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 2015* or *BP Strategic Report 2015* (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, BP Sustainability Report, BP Statistical Review of World Energy* and *BP Technology 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 248 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.

« Defined on page 256.

Registered office and our worldwide headquarters:

BP p.l.c.

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UK

Tel +44 (0)20 7496 4000

Our agent in the US:

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501 Westlake Park Boulevard

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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Chairman s letter

$7.3bn

dividends to BP shareholders

7.5%

ordinary shareholders annual dividend yield «

7.7%

ADS shareholders annual dividend yield «

Dear fellow shareholder,

2015 has been another challenging year: oil prices have remained low, falling by more than 50% and our industry finds itself in a position not seen for some 30 years. This sustained low price is a result, not of lack of demand, but of oversupply. However, our work in reconfiguring BP following the incident in the Gulf of Mexico has meant that we were prepared and well positioned to respond to this volatile environment as we move through 2016.

Shareholders and distributions

We have maintained our dividend during the year and remain committed to growing sustainable free cash flow and shareholder distributions over the long term. I believe that our current financial framework can support these commitments.

The board considers shareholder distributions in the context of how to achieve long-term growth and value creation. In the current weaker price environment, our aim is to rebalance our sources and uses of cash to ensure we cover capital expenditure and shareholder distributions with operating cash flow.[a] This will enable BP to continue to develop its business while maintaining safe and reliable operations. We anticipate that all the actions we are taking will capture more deflation and drive the point of rebalance to below $60 per barrel. The board will keep all of this under review and will make any adjustments to our financial framework as circumstances require.

Strategy

The proposed consent decree with the United States federal government and settlements with the US Gulf states are an important step. It has enabled us to look at the future with greater confidence. However the current price environment continues to be a cause for concern and so we have set a financial path for the next two years. This medium-term strategy is based on optimizing our deployment and allocation of capital and the continuing simplification of our business while maintaining our commitment to safety and reliability.

Our financial results over the year demonstrated the benefit from the integration of our upstream and downstream activities. We have a strong, refocused and rebalanced portfolio based on our distinctive capabilities which we believe will enable us to withstand lower prices. In the future, we will continue to invest in a balanced range of resources and geographies across the Upstream and Downstream to enable us to achieve long-term growth.

We have recently published our *BP Energy Outlook.* I believe this makes an important contribution to the discourse and debate in this area. As the world continues to develop economically then oil, and increasingly gas, will be needed for the foreseeable future. This is the core of our business. Overall we keep under review the broader strategic direction of the group as the market for our products evolves and the energy landscape starts to change.

2015 has seen increased focus on climate change. BP has consistently argued for a price on carbon and recognized the part we all must play in being part of the solution. However governments must take the lead in developing policies to reduce carbon emissions and we continue to engage in this debate. The UN conference on climate change has produced

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Board performance

For information about the board and

its committees see page 55.

Remuneration

For information about our directors

remuneration see page 76.

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Top: The safety, ethics and environmental assurance committee (SEEAC) examine safety measures at our operations in the Khazzan field in Oman.

Bottom: SEEAC members meeting crew on the Cassia platform in Trinidad and Tobago where they inspected the safety of operations.

[a] See Our financial framework on page 19.

some clear results and I am proud of the part that Bob has played in leading the initiative within our industry. At our last AGM in April the board was pleased to support a resolution brought by a group of our shareholders that encouraged greater disclosure of our work in this area; our evolving response to this is set out in our Sustainability Report due for publication this March.

Oversight

The world continues to be a troubled place and the risks faced by BP are ever evolving. The board keeps under review its approach to the monitoring of risk as demonstrated by the board s oversight of cybersecurity and the sharpened focus on geopolitical risk through the formation of the geopolitical committee. This is complemented by the work of our international advisory board. As we progress with our litigation in the US, we expect to stand down the Gulf of Mexico committee during 2016 and I would like to thank my colleagues for the important work and focus they have given to this committee over the past five years. Oversight of the continuing litigation will fall to the full board.

Governance and succession

Membership of the board has continued to be refreshed and during the year Paula Reynolds and Sir John Sawers joined us as non-executive directors. Paula brings deep experience from the financial and energy worlds, while John brings long experience of international politics and security that are so important to our business. Professor Dame Ann Dowling has taken the chair of the remuneration committee in anticipation of Antony Burgmans standing down from the board after twelve years. Antony has chaired the remuneration committee and is also chairing the newly formed geopolitical committee until April when Sir John Sawers will succeed him. Phuthuma Nhleko, who joined the board in 2011, has decided not to offer himself for re-election at the forthcoming AGM due to external business commitments. On behalf of the board I thank Antony and Phuthuma for the substantial contribution that they have made to all of our work.

In 2015 Bob and his executive team have worked determinedly to steer the business through some difficult times with some tough decisions. They have met every challenge and as a result the business is in robust shape as we go into 2016. They deserve our thanks as do all our employees. I would like to thank the board for all that they have done.

And I would like to thank our shareholders for your continued support. We are set to continue supplying energy to help meet global demand while delivering value to you from a great business.

Carl-Henric Svanberg

Chairman

4 March 2016

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Group chief executive s letter

94.7%

2015 refining availability«.

95%

Upstream BP-operated plant reliability«.

Dear fellow shareholder,

In 2015 we continued to adapt to the tough environment created by the dramatic drop in oil prices. We have seen prices crash before, but this fall has been particularly steep, from over $100 a barrel in mid-2014 to below $30 by January 2016. The work we have done to reshape and strengthen BP after 2010 stood us in good stead to withstand these conditions and last year we took further action to make the business more resilient in the short term. We also continue to invest for long-term growth. Our safety record improved, along with operating reliability, while costs came down and capital discipline was maintained. The current environment has however impacted our financial results, as well as those of our competitors. So, while the oil price is beyond our control, we have performed strongly on the factors that we can control.

A safer, more reliable, more resilient BP

In terms of safety, our top priority, we achieved improvements year-on-year in all of our key safety measures process safety events, leaks, spills and other releases, and recordable injuries. This performance is at a much better level than five years ago and in line with the best among our peers. Safety is also good business. When we operate safely, our operations are more reliable. When the assets run reliably, they operate more continuously. When our operations run efficiently, we have better financial results.

In the current business environment, competitiveness depends on minimizing our costs and being disciplined in our use of limited capital as demonstrated by our organic capital expenditure in 2015 of $18.7 billion, down from nearly $23 billion in 2014. And we continue to focus our portfolio on the highest quality projects and operations, divesting $10 billion worth of assets in 2014 and 2015, in line with our target.

2015 was a challenging year for our Upstream business, with weaker oil and gas realizations leading to a significantly lower underlying pre-tax replacement cost profit of $1.2 billion. However, efficiency and reliability improved across the business in 2015. Upstream unit production costs were down 20% on 2013, and BP-operated plant reliability increased to 95% from 86% in 2011. We have made our base production more resilient by improving our reservoir management and increasing efficiencies in our drilling and operations lowering the decline rate and reducing non-productive time in drilling to its lowest level since 2011. And the decision to manage our US Lower 48 business separately is starting to deliver improvements in performance and competitiveness.

Our Downstream business had a record year, delivering $7.5 billion of underlying pre-tax replacement cost profit, demonstrating the benefit of being an integrated business. Our refining business is ranked among the top performers based on net cash margin in the most recent industry benchmark. We made improvements in safety, efficiency and operational performance, and continued to develop a portfolio of highly competitive assets and products. These include the launch in Spain of a new range of fuels with engine-cleaning and fuel-economy benefits, the unveiling of *Nexcel* from *Castrol* a technology with the potential to revolutionize the oil changing process in vehicles, and the start-up of Zhuhai 3 in China one of the most efficient purified terephthalic acid production units in the world.

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Strategy

For more information on our strategic priorities and longer-term objectives see pages 12-17.

Industry context

See how we are responding to the lower price environment on pages 18-19.

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Top: Bob Dudley meets Russian deputy prime minister for social affairs, Olga Golodets, at the London Science Museum Cosmonauts exhibition.

Bottom: Bob Dudley speaks with Pemex CEO, Emilio Lozoya Austin and Total CEO Patrick Pouyanné at the OGCI event in Paris.

Our executive vice president for corporate business activities, Katrina Landis, decided to step down after a very successful 24 years in BP. We have taken this opportunity to simplify and better align responsibilities within the team, appointing Lamar McKay as deputy chief executive, leading on key accountabilities such as strategy and safety, with Bernard Looney succeeding Lamar as Upstream chief executive.

Building a platform for growth

The agreements we reached in July with US federal, state and the vast majority of local government bodies will, subject to court approval, settle our largest remaining legal exposures relating to the Deepwater Horizon accident and oil spill in 2010. This is a realistic outcome that gives BP clarity to plan for the future.

To build that future, we are continuing to invest in a disciplined way in a portfolio that is well balanced in several respects geographically across regions, across our upstream and downstream businesses and across resource types conventional and unconventional oil and gas, as well as the renewable energies of biofuels and wind. This gives us resilience and flexibility now and in the future.

In the Upstream, in addition to a well-managed base of existing operations, we had three major project start-ups in 2015 and we made final investment decisions on four projects, including the West Nile Delta project in Egypt, where we are seeing some best-in-class drilling performance. Looking ahead, we expect significant new production from projects starting up between 2015 and 2020, including our mega projects at Shah Deniz 2 in Azerbaijan and Khazzan in Oman, which will create value for decades. These projects are on time and on budget.

In the Downstream, we continue to focus on resilient and improving performance and growth from a quality portfolio of high-performing refineries, a competitive petrochemicals business and growing fuels marketing and lubricants businesses.

In 2015 we furthered our relationship with Rosneft to that of a strategic partner, with involvement in exploration, appraisal and production in some of the world s most prolific oil and gas provinces. In China, we have signed new agreements to supply liquefied natural gas and to explore for shale gas. And we continue to build relationships in BP s historic heartlands of the Middle East, with growing opportunities in Oman, Kuwait, Egypt and Iraq.

Acting on climate change

We continue to support action to address the risk of climate change. Through the Oil and Gas Climate Initiative a business coalition that accounts for over a fifth of global oil and gas production we are sharing best practices and developing common approaches, such as on the role of natural gas, the lowest-carbon fossil fuel and on energy efficiency. We also joined with BG Group, Eni, Reliance, Repsol, Royal Dutch Shell, Statoil and Total to call on the UN and governments to put a price on carbon so that businesses and consumers of energy can better work within frameworks that are clear.

We welcome the direction provided by the historic agreement reached at the UN climate conference in Paris. Governments, companies and consumers all have to make an appropriate contribution and we will continue to play our part through means including energy efficiency, renewable energy and increasing the share of natural gas in our portfolio.

Adapting for now and the future

Over the years BP has responded to changing circumstances many times. Each time we have learned, adapted and evolved. This experience, gained over more than 100 years, is one of our greatest assets. Today, we are well placed to weather the storm and navigate through a testing environment to emerge in good shape for taking advantage of new opportunities. I am confident that BP will be delivering energy for our customers and value for our shareholders long into the future.

Bob Dudley

Group chief executive

4 March 2016

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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 challenges facing our industry.

Our markets in 2015

See page 24 for information on oil and gas prices in 2015.

Global energy consumption by region

(billion tonnes of oil equivalent)

Source: *BP Energy Outlook.*

Near-term outlook

The global economy continues to experience weaker growth in the main developing economies and slower than expected recovery in the developed world. World gross domestic product (GDP) is expected to grow by 2.8% in 2016, led by the OECD, but with significant downside risks from emerging economies, particularly commodity exporters.

After around four years of averaging about $100 per barrel, oil prices fell by nearly 50% in 2015. Even as US production growth stalled and global oil demand rebounded, a large increase in OPEC production continued to push inventories higher. Price declines continued into early 2016, with daily prices reaching levels not seen since 2004.

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

Affordability

Fossil fuels are currently cheaper than renewables but their future costs are hard to predict. Some fossil fuels may become more costly as the difficulty to access and process them increases; others may be more affordable with technological progress, as seen with US shale gas. While many renewables remain expensive, innovation and wider deployment are likely to bring down their costs.

Supply security

Energy resources are often distant from the hubs of energy consumption and in places facing political uncertainties. More than half of the world s known oil and natural gas reserves are located in just eight countries.

Sustainability

Fossil fuels though plentiful and currently more affordable than other energy resources emit carbon dioxide (CO_2) and other greenhouse gases (GHG) through their intense change for the industry as it adapts to this new reality.

Long-term outlook

The world economy is likely to more than double from 2014 to 2035, largely driven by rising incomes in the emerging economies and a projected population increase of 1.5 billion.

We expect world demand for energy to increase by as much as 34% between 2014 and 2035. This is after taking into account improvements in energy efficiency, a shift towards less energy-intensive activities in fast-growing economies, governmental policies that incentivize lower-carbon activity, and national pledges made at the 2015 UN climate conference in Paris.

There are more than enough energy resources to meet this growing demand, but there are a number of challenges.

production and use in homes, industry and vehicles. Renewables are lower carbon but can have other environmental or social impacts, such as high water consumption or visual intrusion.

Effective policy

BP believes that carbon pricing is the most comprehensive and economically efficient policy to limit GHG emissions. Putting a price on carbon one that treats all carbon equally, whether it comes out of a smokestack or a car exhaust would make energy efficiency more attractive and lower-carbon energy sources, such as natural gas and renewables, more cost competitive. A carbon price incentivizes both energy producers and consumers to reduce their GHG emissions. Governments can put a price on carbon via a well-constructed carbon tax or cap-and-trade system.

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The *BP Technology Outlook* shows how technology can play a major role in meeting the energy challenge by widening energy resource choices, transforming the power sector, improving transport efficiency and helping to address climate concerns out to 2050.

See *bp.com/technologyoutlook*

BP Energy Outlook provides our projections of future energy trends and factors that could affect them out to 2035, 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*

Our strategy

Find out how BP can help meet

energy demand for years to come

on page 12.

Climate change

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.

All sorts of energy required

We believe a diverse mix of fuels and technologies is needed to meet growing energy demand, while supporting the transition to a lower-carbon economy. These are reasons why our portfolio includes oil, gas and renewables.

Oil and natural gas

Over the next few decades, we think oil and natural gas are likely to continue to play a significant part in meeting demand for energy. They currently account for around 56% of total energy consumption, and we believe they will decrease to about 54% in 2035. For comparison, under the International Energy Agency s most ambitious climate policy scenario (the 450 scenario[a]), oil and

We believe shale gas will contribute more than half of the growth in natural gas globally between 2014 and 2035. In the US, the growth of shale gas has already had a significant impact on gas demand as well as CO_2 emissions, which have fallen back to 1990s levels.

The increasing gas supply in the US and other countries is encouraging the use of liquefied natural gas worldwide, which is expected to double between 2014 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.

Renewables

Renewables are the fastest-growing energy source. Over the past few years, there has been rapid expansion of the use of solar power due to cost reduction in manufacturing and public subsidies. That said, renewables, excluding large-scale hydroelectricity, currently account for around 3% of energy consumption. While they are starting from a low base, we estimate that by 2035 they will contribute around 9% of total

Our sector has an important part to

play in addressing climate change.

See page 46 to find out what BP

is doing.

gas would still make up 50% of the energy mix in 2030 and 44% in 2040 assuming carbon capture and storage is widely deployed.

Oil is a good source of energy for transportation as it has a high energy density. That means vehicles go further on less weight and volume of fuel than alternatives. Also, oil s liquid form makes it easy to move around, globally and locally. For these reasons, we expect oil to still account for almost 90% of transportation fuels in 2035 compared with 94% today.

Natural gas is likely to play an increasing role in meeting global energy demand, because it s available at scale, relatively low cost and lower carbon than other fossil fuels. By 2035 gas is expected to provide 26% of global energy, placing it on a par with oil and coal.

[a] From *World Energy Outlook 2015*. © OECD/International Energy Agency 2015, page 35. The IEA 450 scenario assumes a set of policies that bring about a trajectory of greenhouse gas emissions from the energy sector that is consistent with limiting long-term average global temperature increase to 2°C.

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 management.

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Our business model and strategy

We aim to create value for our investors and benefits for

the communities and societies where we operate.

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The new semi-submersible Deepsea Aberdeen drilling vessel carries out ultra-deepwater drilling in the UK North Sea.

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An officer working in the under-deck pipe passageway on board BP s LNG tanker *British Trader*.

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 28 and 34 respectively.

Our business model

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 balanced across resource types, geographies and businesses, and adaptable to prevailing conditions. Our geographic diversity gives us access to growing markets and new resources and provides robustness to geopolitical events.

By having upstream and downstream businesses and well established trading capabilities, we have a cushion to oil price volatility as downward pressures in one part of the group can create opportunities in another. Integration also 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.

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Industry context

See how we are responding to the lower price environment on pages 18-19.

Our key performance indicators

See how we measure our progress on page 20.

Risks

Find out how we manage the risks to our strategy on page 51.

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.

Our strategy

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

We aim to create shareholder value by growing sustainable free cash flow« and distributions over the long term.

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

Clear priorities

Quality portfolio

We undertake active portfolio management to concentrate on areas where we can play to our strengths. We focus on high-value upstream assets in deep water, giant fields, selected gas value chains and unconventionals«. And, in our downstream businesses, we plan to leverage our upgraded assets, customer relationships, brand and technology to continue to grow free cash flow.

Our portfolio of projects and operations is focused where we believe we can generate the most value, using our commercial agility and technical capability. This allows us to build a strong pipeline of future growth.

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 more than 70 countries across the globe. And the proven expertise of our employees comes to the fore in a wide range

First, we aim to run safe, reliable and compliant operations leading to better operational efficiency and safety performance. We target competitive project execution to deliver projects as efficiently as possible. Making disciplined financial choices focused on capital and cost discipline allows us to maximize free cash flow and increase the resilience of our portfolio to changing price environments.

of disciplines.

« Defined on page 256.

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Our strategy in action

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How we deliver	How we measure	Strategy in action in 2015	
We prioritize the safety and reliability of our operations to protect the welfare of our workforce, local communities and the environment, and to improve the efficiency of our operations. 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.	**Improving reliability** Improvement plans are increasing UK North Sea plant reliability. See page 44.	20 tier 1 process safety events 2014: 28
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.	**Capturing value** Improving the quality of future investments. See page 30.	$19.1bn operating cash flow 2014: $32.8bn
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.	**Adapting rapidly** Using local knowledge to increase our competitiveness. See page 29.	3 major project start-ups in Upstream 2014: 7
We target opportunities with the greatest potential to increase value, using our commercial agility and technical capability. This allows us to build a strong pipeline for future growth.	Proved reserves replacement ratio.	**Unlocking energy potential** Investing in exploration and development in Egypt. See page 33.	61% reserves replacement ratio[a] 2014: 63%
We are strengthening our portfolio of high-return and longer-life assets across deep water, giant fields, gas value	Production.	**Optimizing our assets** Using our technical	3.3 million barrels of oil equivalent per

chains and unconventionals to provide BP with momentum for years to come.

expertise to maintain a secure and reliable supply.

day[a]

2014: 3.2 million

See page 31.

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.

Improving operations

Improvements at Castellón refinery are helping to increase profitability.

94.7%

refining availability

2014: 94.9%

See page 36.

Creating shareholder value by generating

sustainable free cash flow over the long term

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 256.

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Our distinctive capabilities

We select and develop the technologies that can best help us manage risk and grow value for our businesses. Our first priority is to enhance the safety and reliability of our operations. Beyond that we aim to build and maintain leadership positions in selected technologies.

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. Our downstream technology programmes are designed to improve the performance of our refineries and petrochemicals plants and create high-quality, energy-efficient products.

q

High-speed graphics workstations in our Sunbury office use state-of-the-art software and projection equipment to create a 3D virtual world.

We employ scientists and technologists at seven major technology centres in the US, UK and Germany. BP and its subsidiaries hold more than 4,500 granted patents and pending patent applications throughout the world. In 2015 we invested $418 million in research and development (2014: $663 million, 2013 $707 million).

We partner 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 and lower-carbon energy sources. For example research at the BP International Centre for Advanced Materials has led to its first patent application on a strong steel alloy that resists becoming brittle and is less likely to crack. This has the potential to enhance the reliability of our equipment.

See bp.com/technology

Seismic imaging

Our *Independent Simultaneous Source (ISS)* technology makes large-scale 3D seismic surveys faster and reduces cost by using multiple surveying sources and receivers at the same time. Our 2015 *ISS* survey at Prudhoe Bay in Alaska delivered a 10-fold increase in productivity, meaning we could acquire higher-quality images in just one winter season.

Production optimization

We began to deploy a new automated well choke control system as part of our *Field of the Future* technology suite in Azerbaijan in 2015. Sand can cause wells to fail, but this system is helping us manage well start-up and unsteady flow during operations, contributing to improved operational efficiency and production rates.

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 and promoting from within the organization and complement this with selective external recruitment. We invest in our employees development to build enduring capability for the future.

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

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Enhanced oil recovery (EOR)

Bright Water technology, invented by BP, helps to maximize oil production by recovering and moving more oil to our wells. We use it in more than 140 wells worldwide to date. It costs less than $5 to recover each additional barrel of oil released through *Bright Water,* and we deliver more light oil EOR production than any other international oil company.

Lubricants

Castrol s new technology, the *Nexcel* oil cell, is an easy-to-change unit containing both engine oil and filter. We believe the technology is a significant oil change innovation for the automotive industry. It is designed to lower CO_2 emissions, improve vehicle servicing and increase the recycling of used oil for cars of the future.

Petrochemicals

BP is one of the world s largest producers of purified terephthalic acid (PTA), a raw material for many consumer products. In 2015 we entered into licensing agreements in Oman and China, for plants that will use our latest generation PTA technology, with a combined capacity to produce more than two million tonnes of PTA each year.

Corrosion prevention

We use automated phased array ultrasonic testing (PAUT) across our refineries to safely inspect our tanks and pipelines. Our PAUT technology uses ultrasonic pulses to examine the integrity of these assets and detect cracks in a non-destructive way. The technique reduces facility downtime, decreases turnaround costs and risks, and avoids production losses.

Fuels

BP began marketing a range of dirt-busting fuels with a launch in Spain in 2015. The fuels contain our new *ACTIVE* technology that cleans and protects car engines with proprietary additives. Our fuels are designed to remove deposits and prevent their formation helping engines perform in the way they were designed to do.

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.

We work closely with governments, national oil companies, other resource holders and local communities 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, shareholders, customers, local communities and other partners.

We believe good communication and open dialogue are vital if we are to meet their expectations.

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Lower oil and gas prices

We are taking action to adapt to a lower oil and gas price environment while maintaining longer-term growth prospects.

Since 2010, we have been working to create a stronger, simpler and more focused business. This has positioned us well to respond to the lower oil and gas price environment. We are reducing capital expenditure by paring back and rephasing activities as necessary, as well as capturing the benefits of deflation of industry costs. We are driving down cash costs« through a reduction in third-party costs, and through efficiency and simplification across the organization. As always, safe and reliable operations are our first priority.

t

Remodelling Mad Dog Phase 2 reduced our project cost estimate by more than half.

Between 2010 to mid-2014 oil prices were relatively stable, averaging around $100 per barrel. In 2014, strong supply growth, largely as a result of growth in US shale, caused oil prices to fall sharply. Prices fell further in 2015 as OPEC production increased and supply continued to

Low prices are having a significant effect on our industry, including BP. With falling revenues, companies need to re-base costs and activity a process that could take several years. We expect 2016 to be a period of intense change, with ongoing restructuring and further deflation in the supply outstrip demand. There are, however, increasing signs that the market is adjusting to the current low level of prices, with strong demand growth and weakening supply. The high level of inventories suggests that this adjustment process is likely to take some time, but it does appear to be underway. This underpins our belief that prices will stay lower for longer, but not forever.

Gas prices also fell, albeit on a more regional and less dramatic scale. In markets such as the US, gas prices are at historically low levels, with increases in production from shale being a key factor.

chain. That said, periods of low prices are not uncommon in our industry and BP has gone through such cycles in the past.

For BP, the lower prices significantly impacted our 2015 financial results. The result for the year was a loss of $6.5 billion. Underlying replacement cost profit« was $5.9 billion (2014 $12.1 billion) and operating cash flow« was $19.1 billion (2014: $32.8 billion).

Sources and uses of cash

The cash flow from our Upstream operations was significantly lower than in 2014 although Downstream cash flows were strong. We significantly reduced the capital expenditure of the group as well as received proceeds from divestments. The strength of our balance sheet helped us meet the balance of outgoings.

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Our financial framework is designed to re-establish a balance where operating cash flow (excluding payments related to the Gulf of Mexico oil spill) covers organic capital expenditure« and the current level of dividend per share by 2017, based on an average Brent« price of around $60 per barrel.

If prices remain lower for longer than anticipated, we expect to continue to recalibrate for the weaker environment and to capture more deflation. We would expect this to drop the balance point below $60 per barrel.

We will keep our financial framework under review as we monitor oil and gas prices and their impact on industry costs as we move through 2016 and beyond.

Our financial framework through 2017

Underpinning our commitment to sustain the dividend for our shareholders

Principle		2015 achievement	Looking ahead
Optimize capital expenditure	g	2015 organic capital expenditure was $18.7 billion. This is 18% down from the 2011-2014 period average.	We expect capital expenditure of $17-19 billion per year in 2016 and 2017 as a result of reducing costs and activity, with 2016 spend towards the lower end of this range.
Reduce cash costs	g	We made significant progress in reducing cash costs compared with 2014.	We anticipate the reduction in our cash costs to be close to $7 billion versus 2014 by the end of 2017.
Make selective divestments	g	We completed the $10-billion divestment programme announced for 2014-2015.	We expect divestments of $3-5 billion in 2016 and $2-3 billion per year from 2017 to help manage oil price volatility and fund the ongoing Gulf of Mexico commitments.
Maintain flexibility around gearing	g	Gearing« at the end of 2015 was 21.6% against a 2011-2014 average of 18%.	Looking ahead, we aim to manage gearing with some flexibility at around 20%. While oil prices remain weak, we expect gearing to be above 20%.

Upstream

We are focusing on the timing of investments to capture deflation in the supply chain, paring back access and exploration spend and prioritizing activity in our base operations. Where we are not the operator, we are influencing partners to focus on third-party costs.

We reduced unit production costs by more than 20% compared with 2013 and achieved an average reduction of 15% in upstream third-party costs in 2015. By the end of 2016, we expect to re-bid 40% of our third-party spend, including a significant proportion of our well services contracts.

Our total upstream workforce including employees and contractors is now 20% smaller than it was in 2013, with a reduction of around 4,000 expected in 2016. We are aiming for an upstream workforce of approximately 20,000 by the end of 2016.

Downstream

In 2015 we reorganized our fuels business from nine regions to three, streamlined the lubricants business and started restructuring petrochemicals. We are implementing site-by-site improvement programmes to drive manufacturing efficiency in refining and petrochemicals. Our focus on third-party spend has resulted in significant cost reductions and we have reduced head office related costs by around 40%.

These simplification and efficiency actions have significantly contributed to the group s cash cost reductions in 2015.

We expect to reduce our downstream workforce roles by more than 5,000 by the end of 2017 compared with 2014, and by the end of 2015 had already achieved a reduction of more than 2,000.

Other businesses and corporate

We made significant progress in reducing corporate and functional costs in 2015. We are focusing on third-party spend and headcount both in response to the lower oil price and also to reflect the changes to our portfolio.

Figures exclude retail staff and agricultural,

operational and seasonal workers in Brazil.

« Defined on page 256.

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Our key performance indicators

We assess our performance across 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.

Remuneration

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

Overall annual bonuses, deferred bonuses and performance shares are all based on performance against measures and targets linked directly to strategy and KPIs.

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 216.

2015 performance The significant reduction in underlying RC profit per ordinary share for the year

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.

2015 performance
Operating cash flow was lower in 2015, largely reflecting the impact of the lower oil price environment.

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 around 20% 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 26.

Directors remuneration

See how our performance

impacted 2015 pay on

page 76.

Key

KPIs used to measure progress

against our strategy.

KPIs used to determine 2015

and 2016 remuneration.

compared with 2014 was mainly due to lower profit in Upstream.

2015 performance
Gearing at the end of 2015 was 21.6%, up 4.9% on 2014.

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.

2015 performance
Refining availability was similar to 2014.

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.

2015 performance Our workforce RIF, which includes employees and contractors combined, was 0.24. This improvement on 2014 was also reflected in our other occupational safety metrics. While this is encouraging, continued vigilance is needed.

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.

2015 performance We have seen a decrease in our loss of primary containment to 235. Figures for 2014 and 2015 include increased reporting due to the introduction of enhanced automated monitoring for remote sites in our US Lower 48 business. Using a like-for-like approach with prior years reporting, our 2015 loss of primary containment figure is 208 (2014 246).

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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.

2015 performance Negative TSR in the year reflects the fall in the BP share price exceeding the dividend.

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.

2015 performance This year s reserves replacement ratio was similar to 2014. See page 229 for more information.

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.

2015 performance We delivered three major projects in Upstream two in Angola and one in Asia Pacific, and started up Zhuhai 3 in Downstream.

Production (mboe/d)

We report production of crude oil, condensate, natural gas liquids (NGLs), natural bitumen and natural gas on a volume per day basis for our subsidiaries and equity-accounted entities. Natural gas is converted to barrels of oil equivalent at 5,800 standard cubic feet of natural gas = 1 boe.

2015 performance BP s total reported production including Upstream and Rosneft segments was 4.0% higher than in 2014. This was mainly due to favourable entitlement impact in our production-sharing agreements in the Upstream segment.

Tier 1 process safety events«[a]

Greenhouse gas emissions[b]

Group priorities index[d] (%)

Diversity and inclusion[d] (%)

(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.

2015 performance The number of tier 1 process safety events has decreased substantially since 2011. We believe our systematic approach to safety management and assurance is contributing to improved performance over the long term and will maintain our focus in these areas.

We provide data on greenhouse gas (GHG) emissions material to our business on a carbon dioxide-equivalent basis. This includes carbon dioxide (CO_2) and methane for direct emissions. 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.[c]

2015 performance The increase in our reported emissions is due to updating the global warming potential for methane. Without this update, our emissions would have decreased primarily due to divestments in Alaska.

We track how engaged our employees are with our strategic priorities using our group priorities index. This is derived from survey questions about their perceptions of BP as a company and how it is managed in terms of leadership and standards.

2015 performance Our group priorities engagement measure fell slightly in 2015, as expected in the current low oil price environment.

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.

2015 performance The percentage of our group leaders who are women or non-UK/US rose slightly. We remain committed to our aim that women will represent at least 25% of our group leaders by 2020.

[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.

[b] The 2015 figure reflects our update of the global warming potential for methane from 21 to 25, in line with IPIECA s guidelines.

[c] For more information on our GHG emissions see page 46.

[d] Relates to BP employees.

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Strategy, performance and pay

In a difficult environment, BP s leadership delivered strong operating performance,

based on a sound strategy and consistently improved safety performance. They have

acted early and decisively in response to low oil prices to preserve future growth.

Highlights of the year

Strong safety and operational performance in a difficult environment

Responded early and decisively to lower oil price environment.

Excellent safety standards with continuous improvement over the past three years, leading to improvements in reliability and operations.

Strong operating cash flow« and underlying replacement cost profit relative to plan.

Net investment managed aggressively to reflect lower for longer oil price environment.

Executive directors pay outcomes reflect strong operating performance relative to plan.

Alignment between executives and shareholders with the majority of executive director remuneration paid in equity with lengthy retention requirements.

In an ever more challenging world BP executives performed strongly in 2015 in managing the things they could control and for which they were accountable. BP was one of the first to recognize the shift to a lower for longer price environment and through early action delivered distinctive competitive performance on costs. Momentum built through the year in simplification and efficiencies, such that operating cash flow significantly exceeded plan. Assets ran well and major projects« were commissioned on time. Good performance on safety has led to sound and reliable operations. There has been a high quality of execution.

Our pay structure is relatively simple and reflects a number of key overriding principles. It is long-term, performance-based and tied directly to strategy and delivery. It is biased towards equity with long retention periods. This is reflected in the policy framework that was approved by shareholders in 2014. Variable remuneration is primarily based on true underlying performance and not driven by factors over which the executives have no control. Consistent with past practice, we normalize for changes in oil and gas price and refining margins. This avoids both windfall gains and punitive losses in periods of extreme volatility such as we are currently experiencing.

Against this background, I am pleased to give an overview of key elements of executive remuneration for 2015. All of the detail is set out in the Directors remuneration report on page 76.

Short-term performance

The annual cash bonus is based on safety (30%) and value (70%) measures directly linked to our KPIs and strategy. In setting annual safety targets, the committee reviews the three-year performance and in each case aims for improvement. We measure value by reference to operating cash flow and underlying replacement cost profit. In addition, two value measures, reductions in corporate and functional costs and net investment (organic)«, reflect progress in simplification. Targets were based on the board s plan set in January 2015, with the maxima tested for stretch. Results were strong across all measures.

Short-term: annual bonus

Measure	Result		Target	Outcome
Safety and operational risk				

Loss of primary containment	Spills and leaks declined.	£ 253 events	**208 events[a]**
Process safety tier 1 events	The most serious process safety events were reduced.	£ 29 events	**20 events**
Recordable injury frequency	Number of work-related recordable injuries per 200k hours fell.	£ 0.261/200k hours[b]	**0.223/200k hours[b]**

For more information on the group s key performance indicators see page 20.

Value			
Operating cash flow	Significantly ahead of plan.	$17.2bn	**$19.1bn**
Underlying replacement cost profit	Significantly ahead of plan.	$4.2bn	**$5.9bn**
Net investment (organic)	Significantly ahead of plan.	i18%	**i27%**
Corporate and functional costs	Significantly ahead of plan.	i5.9%	**i17.6%**
Major project delivery	On target.	4	**4**

[a] Adjusted in accordance with the treatment of the loss of primary containment key performance indicator on page 20.
[b] Excludes biofuels.

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The safety and operational risk performance has been excellent. This has led to increased reliability and more efficient operations. There is a proposed settlement of the federal and state claims and settlement of most of the local government claims relating to the Deepwater Horizon incident. BP responded quickly and decisively to the drop in oil price, continuing to simplify its activities and significantly reducing its cost base. Capital discipline has been demonstrated in a strategic way that offers flexibility and resilience now and options for future growth. Our belief is that management has delivered very well in a difficult year.

The overall group score achieved was 1.91 out of a maximum of 2.00. As is our normal practice, the committee reviewed this result and considered whether it produced a fair outcome in light of the underlying performance of the company and the wider environment. As part of this both the committee and the

Long-term: performance share plan

Measure	Result	Target	Outcome
Relative TSR	BP s TSR ranked third versus other oil majors.	Outperform peers	**Third**
Operating cash flow	Strong operating cash flow in 2015 relative to plan.	$17.7bn	**$19.1bn**
Strategic imperatives			
Relative reserves replacement ratio (RRR)	BP s RRR preliminary ranked first versus other oil majors.	Outperform peers	**First**
Safety and operational risk:	Downward trend over the last three years.		
Loss of primary containment		£ 212 events	**208 events[a]**
Process safety tier 1 events		£ 30 events	**20 events**
Recordable injury frequency		£ 0.240/200k hours[b]	**0.223/200k hours**
Major project delivery	15 major projects were commissioned.	11	**15**

[a] Adjusted in accordance with the treatment of the loss of primary containment key performance indicator on page 20.

[b] Excluding biofuels.

Pay outcomes

The resulting remuneration for executive directors is shown below. Consistent with the wider

three-year retention period before being released to the individual.

group chief executive believed some recognition of the dramatic fall in oil prices and its impact on shareholders was warranted. As a result the group score was lowered to 1.70 and this has been used to determine annual bonuses for BP s wider management group. For executive directors our approved policy limits annual bonus to 1.50.

Long-term performance

The 2012 deferred bonus was contingent on safety and environmental sustainability over a three-year period. The committee saw good evidence of a continued improvement on safety that is both ingrained in the culture and has led to more reliable and efficient operations. The award vested in full.

The 2013-15 performance share plan was, as in previous years, based on three sets of measures equally weighted: relative total shareholder return (TSR) over the three-year period, 2015

population of BP employees, executive directors received no increase in base salary in 2015. This is being continued with no salary increase for the senior leadership and executive directors in 2016.

As described above, annual bonus was limited to a group score of 1.50, the 2012 deferred bonus vested fully and 77.6% of shares in the 2013-2015 performance share plan are expected to vest. These will be finally determined later in the year when results from all oil majors are known. The shares that vest will have a further

Total remuneration (excluding pensions)

Conclusion

In conclusion, BP has performed well and surpassed the board s expectations on almost all of the measures. I am pleased that our current policy has appropriately recognized this in the 2015 outcomes. There remain challenging times with an evolving remuneration landscape. During 2016, the committee will be undertaking a full review of our policy. I have already met with some of our key shareholders and look forward to continuing this engagement as we develop a

In our assessment, the overall quantum of remuneration is market competitive and represents a balanced outcome. It is based heavily on performance and mainly paid in equity with long retention periods. Executive directors are required to hold shares in excess of five-times salary. While the value of their shares has, as for all shareholders, dropped with the oil price, they satisfy that requirement.

For the single figure remuneration

table see page 77.

new proposed policy for approval at the 2017 Annual General Meeting.

BP is a strong company with strong leadership. The company continues to evolve as will our remuneration policy and practice to ensure we remain performance driven and competitive.

Professor Dame Ann Dowling

Chair of the remuneration committee

operating cash flow and finally, strategic imperatives which included safety and operational risk, relative reserves replacement ratio (RRR) and major project delivery over the three years.

For TSR, BP was in third place. The target set in 2013 for operating cash flow in 2015 was $35 billion based on the plan assumptions. At the start of the year, this was normalized for the change in oil and gas price, and refining margins since 2013. We also, as in previous years, adjusted for major divestments and for contributions to the Gulf of Mexico restoration. The resulting target was $17.7 billion. This compared to an outcome of $19.1 billion. Safety performance at the end of the three-year period, against targets previously set at the outset, was strong. The final results from the comparator group for RRR are not yet available but on the evidence, our preliminary assessment is that the company is in first place. There will be a final assessment later in the year. Major project delivery exceeded target.

As a result 77.6% of the shares are expected to vest. Reviewing the period 2013-15, the committee believes that this represents a fair outcome. In that time there has been the delivery of the 10-point plan in 2014, consistent improvements in safety performance and effective budgetary and capital discipline in difficult circumstances.

« Defined on page 256.

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Our markets in 2015

A snapshot of the challenging global energy market in 2015.

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More than 200 of our UK BP stores have an M&S Simply Food® outlet. This premium offer is helping to drive overall service station sales growth.

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Construction of *Glen Lyon,* our new 270 metre long floating, production, storage and offloading vessel, at a shipyard in South Korea.

BP Statistical Review of World Energy

See *bp.com/statisticalreview* for an objective review of key global energy trends.

Crude oil prices (quarterly average)

Natural gas prices (quarterly average)

The global economy struggled to return to a more normal pace of growth in 2015 GDP growth estimates were revised down over the course of the year, with latest estimates indicating that the world economy grew by 2.5% in 2015, compared to trend growth of around 3%. Slowing growth in China contributed to falling commodity prices, weak global trade and weakening emerging market growth. The developed world also failed to take off as expected with the US, EU and Japan all underperforming.

Oil

Crude oil prices averaged $52.39 per barrel in 2015, as demonstrated by the industry benchmark of dated Brent«, nearly $47 per barrel below the 2014 average of $98.95. This was the largest oil price decline ever in inflation-adjusted terms and it was the third-largest percentage decline (behind 1873 and 1986). Prices recovered in the second quarter, averaging nearly $62, but fell later in the year as OPEC production increased and inventories grew. Brent prices ended the year near $35.

In 2014 global oil consumption grew by roughly 0.8 million barrels per day (0.8%), significantly slower than the increase in global production (2.3%).[b] Non-OPEC production once again accounted for all the net global increase, driven by record US growth.

Natural gas

Global price differentials in 2015 continued to narrow. US gas prices and Asian transacted LNG prices were more than 40% lower, while European transacted LNG prices were 15% lower. The Henry Hub« First of the Month index fell from $4.43 per million British thermal units (mmBtu) in 2014 to $2.67 in 2015 as supply growth continued to be resilient.

Transacted 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 added 1.4bcf/d of supply capacity to the LNG market in 2015.

In response to the sharp decline in world oil prices, global oil consumption increased by an above-average 1.6 million barrels per day (mmb/d) for the year (1.7%).[a] While emerging economies accounted for the majority of growth, the mature economies of the OECD recorded a rare increase as well. The robust growth in consumption was once again exceeded by growth in global production. Non-OPEC production growth slowed to 1.4mmb/d as US production peaked in the second quarter in the face of a rapid contraction in investment and drilling.[a] OPEC crude oil production, however, accelerated, growing by 1.1mmb/d in 2015.[a] As a result, OECD commercial oil inventories reached record levels late in the year.

[a] From IEA Oil Market Report, February 2016 ©, OECD/IEA 2016, Page 4.

[b] *BP Statistical Review of World Energy 2015.*

Moderating demand and ample supplies from both Russia and LNG markets reduced the UK National Balancing Point« hub price to an average of 42.61 pence per therm in 2015 (2014 50.01). The Japanese spot price fell to an average of $7.45/mmBtu in 2015 (2014 $13.86) with weaker demand from North Asian consumers coinciding with rising supplies in the region.

In 2014 growth in natural gas consumption was at its slowest rate for the last 20 years with the exception of the financial crisis of 2008-09. Broad differentials between regional gas prices narrowed considerably, as US gas prices continued their recovery from their 2012 lows. Global LNG supply capacity expanded further in 2014, following a small increase in 2013, while growth in LNG demand moderated.

Prices and margins

See pages 29 and 35.

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BP is embedding cost efficiency and simplification into everyday activities as well as large-scale changes in response to market conditions.

As with other companies within our industry, BP is taking measures to respond to the impact of a lower-price environment by limiting capital spend, looking to benefit from cost deflation and reducing headcount. In addition, for some time we have been encouraging everyone in BP to find and implement smarter ways of working, without compromising safety. From large-scale behaviour changes to small and simple ideas, our employees are helping to make a positive difference to the reliability and efficiency of our operations.

A helicopter-sharing first t

When changing crews on board BP s Skarv platform in the Norwegian North Sea, a helicopter flies the replacement team offshore and brings the current team back to land. On these journeys an average of six of the 19 seats were unused. We discovered that nearby operator, Statoil, was in the same situation and so looked for opportunities to maximize seat usage on our journeys. Statoil offered BP a 50% share in its contracted helicopter capacity and the companies entered into a cost-sharing agreement for scheduled flights. With fewer flights offshore we have reduced costs and CO_2 emissions.

Easing the bottleneck q

The Cherry Point refinery rail facility receives crudes directly from US and Canadian producers. But with only two tracks available, the mile-long trains often had to wait to offload their oil supply. This prevented the refinery from maximizing its rail offloading efficiency. Teams at the site, along with the supply organization, worked to resolve the problem by installing additional track to reduce congestion and allow full utilization of the rail facility. In 2015 we safely executed this rail upgrade ahead of schedule and

Foundations for success p

BP drilling and cementing teams in Azerbaijan regularly review well design and construction to ensure they are safe, efficient and reliable. In efforts to improve cementing technology, a key element of well construction, the teams identified ways to simplify the process and decrease drying times. By changing cement and optimizing parameters, drying time has been reduced and more than $1 million has been saved. The process can be replicated elsewhere.

within budget.

Steam clean savings p

Refinery tank cleaning, which is done by hand, is not always efficient as it is based on estimates of waste within the tank. Downstream teams tested an existing steam injection method that was new to BP that separates the build up into sediment on the bottom, then water, and a layer of recoverable oil floating on the top. The oil and water are pumped away, leaving the sediment to be easily cleaned up in the final manual cleaning step. Since the process was implemented at the Rotterdam refinery in 2015, it has significantly reduced cleaning times from 9-12 months down to three, reduced risks to cleaners and saved more than $3 million. It is now being adopted across BP with further savings expected.

Logistics planning p

Driving supply boats to our offshore Egypt rigs can consume a lot of fuel. Through detailed logistics planning we calculated that a 25% reduction in speed consumed about 40% less fuel per trip. We also found that keeping a vessel outside the 500 metre rig zone required less engine power than the full dynamic positioning mode needed within it, and this reduced fuel consumption by around 80%. We have applied these changes across the region s fleet and are expecting to save more than $400,000 a year. We are sharing this cost-saving approach globally.

Making storage simpler u

Throughout more than 50 years of operations in the North Sea, BP had built up large quantities of equipment that were spread around 172 locations, with significant storage fees and long lead times to get these materials offshore. By updating and improving our materials management process we reduced the number of stored inventory items by half and brought the number of storage locations down by about 65%. We also generated around $32 million by selling surplus materials and scrap.

« Defined on page 256.

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Group performance

A summary of our group financial and

operating performance.

p

A technician monitors the pressure gauges in the enhanced oil recovery laboratory in Sunbury.

Financial and operating performance

			$ million
	2015	2014	2013
Profit (loss) before interest and taxation	**(7,918)**	6,412	31,769
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(1,653)**	(1,462)	(1,548)
Taxation	**3,171**	(947)	(6,463)
Non-controlling interests	**(82)**	(223)	(307)
Profit (loss) for the year[a]	**(6,482)**	3,780	23,451
Inventory holding (gains) losses«, net of tax	**1,320**	4,293	230
Replacement cost profit (loss)«	**(5,162)**	8,073	23,681
Net charge (credit) for non-operating items«, net of tax	**11,272**	4,620	(10,533)
Net (favourable) unfavourable impact of fair value accounting effects«, net of tax	**(205)**	(557)	280
Underlying replacement cost profit«	**5,905**	12,136	13,428
Dividends paid per share cents	**40.0**	39.0	36.5
pence	**26.383**	23.850	23.399
Capital expenditure and acquisitions, on an accruals basis	**19,531**	23,781	36,612

[a] Profit (loss) attributable to BP shareholders.

The result for the year ended 31 December 2015 was a loss of $6.5 billion, compared with a profit of $3.8 billion in 2014. Excluding inventory holding losses, replacement cost (RC) loss was $5.2 billion, compared with a profit of $8.1 billion in 2014.

After adjusting for a net charge for non-operating items, which mainly related to the agreements in principle to settle federal, state and the vast majority of local government claims arising from the 2010 Deepwater Horizon accident and impairment charges; and net favourable fair value accounting effects, underlying RC profit for the year ended 31 December 2015 was $5.9 billion, a decrease of $6.2 billion compared with 2014. The reduction was mainly due to a significantly lower profit in Upstream, partially offset by improved earnings from Downstream.

Non-operating items in 2015 also included $1,088 million for restructuring charges that largely relate to rationalization and reorganization costs in response to the low oil and gas price environment. A further $1.0 billion of restructuring charges are expected to be incurred in 2016.

Profit for the year ended 31 December 2014 decreased by $19.7 billion compared with 2013. Excluding inventory holding losses, RC profit 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.

More information on non-operating items, and fair value accounting effects, can be found on page 217. See Gulf of Mexico oil spill on page 41 and Financial statements Note 2 for further information on the impact of the Gulf of Mexico oil spill on BP s financial results.

See Upstream on page 28, Downstream on page 34, Rosneft on page 38 and Other businesses and corporate on page 40 for further information on segment results. Also see page 41 for further information on the Gulf of Mexico oil spill.

Taxation

The credit for corporate income taxes in 2015 reflects the deferred tax impact of the increased provisions in respect of the Gulf of Mexico oil spill. The effective tax rate (ETR) was 33% in 2015 (2014 19%, 2013 21%).

The ETR in 2015 compared with 2014 was impacted by various one-off items. Adjusting for inventory holding impacts, non-operating items, fair value accounting effects and the one-off deferred tax adjustment in 2015 as a result of the reduction in the UK North Sea supplementary charge, the underlying ETR on RC profit was 31% in 2015 (2014 36%, 2013 35%). The underlying ETR for 2015 is lower than 2014 mainly due to changes in the geographical mix of profits.

The ETR in 2014 was similar to 2013 and was relatively low in both years. The low ETR in 2014 reflected the impairment charges on which tax credits arise in relatively high tax rate jurisdictions. The ETR in 2013 reflected the gain on disposal of TNK-BP in 2013 for which there was no corresponding tax charge.

In the current environment, and with our existing portfolio of assets, the underlying ETR in 2016 is expected to be lower than 2015 due to the anticipated mix of profits moving away from relatively high tax Upstream jurisdictions.

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Cash flow and net debt information

			$ million
	2015	2014	2013
Net cash provided by operating activities	**19,133**	32,754	21,100
Net cash used in investing activities	**(17,300)**	(19,574)	(7,855)
Net cash used in financing activities	**(4,535)**	(5,266)	(10,400)
Cash and cash equivalents at end of year	**26,389**	29,763	22,520
Gross debt	**53,168**	52,854	48,192
Net debt«	**27,158**	22,646	25,195
Gross debt to gross debt-plus-equity	**35.1%**	31.9%	27.0%
Net debt to net debt-plus-equity«	**21.6%**	16.7%	16.2%

KPIs used to measure progress against our strategy.

Net cash provided by operating activities

Net cash provided by operating activities for the year ended 31 December 2015 was $13.6 billion lower than 2014, of which $1.1 billion related to the Gulf of Mexico oil spill. This was principally a result of the lower oil price environment, although there were benefits of reduced working capital requirements and lower tax paid.

There was an increase of $11.7 billion in 2014 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, 2014 was impacted by a favourable movement in working capital.

Net cash used in investing activities

Net cash used in investing activities for the year ended 31 December 2015 decreased by $2.3 billion compared with 2014. The decrease mainly reflected a reduction in capital expenditure of $3.9 billion in response to the lower oil price environment, partly offset by a reduction of $0.7 billion in disposal proceeds.

The increase of $11.7 billion in 2014 compared with 2013 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.

There were no significant acquisitions in 2015, 2014 and 2013.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $20.2 billion in 2015 (2014 $23.1 billion and 2013 $30 billion). Sources of funding are fungible, but the majority of the group s funding requirements for new investment comes from cash generated by existing operations.

We expect capital expenditure, excluding acquisitions and asset exchanges, to be at the lower end of the range of $17-19 billion in 2016.

Total cash disposal proceeds received during 2015 were $2.8 billion (2014 $3.5 billion, 2013 $22.0 billion). In 2015 this included amounts received from our Toledo refinery partner, Husky Energy, in place of capital commitments relating to the original divestment transaction that have not been subsequently sanctioned. In 2013 this included $16.7 billion for the disposal of BP s interest in TNK-BP. See Financial statements Note 4 for more information on disposals.

We have now completed the $10-billion divestment programme which we announced in 2013. We expect divestments to be around $3-5 billion in 2016 and ongoing divestments to be around $2-3 billion per annum thereafter.

Net cash used in financing activities

Net cash used in financing activities for the year ended 31 December 2015 decreased by $0.7 billion compared with 2014. There were no share repurchases in 2015, compared with $4.6 billion in 2014. This was largely offset by lower net proceeds from financing of $3.2 billion ($4.4 billion

lower net proceeds from long-term debt offset by an increase of $1.2 billion in short-term debt).

The decrease of $5.1 billion in 2014 compared with 2013 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.

Total dividends paid in 2015 were 40 cents per share, up 2.6% compared with 2014 on a dollar basis and 10.6% in sterling terms. This equated to a total cash distribution to shareholders of $6.7 billion during the year (2014 $5.9 billion, 2013 $5.4 billion).

Net debt

Net debt at the end of 2015 increased by $4.5 billion from the 2014 year-end position. The net debt ratio« at the end of 2015 increased by 4.9%.

The total cash and cash equivalents at the end of 2015 were $3.4 billion lower than 2014.

We aim to maintain the net debt ratio, with some flexibility, at around 20%. We expect the net debt ratio to be above 20% while oil prices remain weak. Net debt and the net debt ratio are non-GAAP measures. See Financial statements Note 26 for gross debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt.

For information on financing the group s activities, see Financial statements Note 28 and Liquidity and capital resources on page 219.

Group reserves and production

	2015	2014	2013
Estimated net proved reserves[a] (net of royalties)			
Liquids« (mmb)	**9,560**	9,817	10,070
Natural gas (bcf)	**44,197**	44,695	45,975
Total hydrocarbons« (mmboe)	**17,180**	17,523	17,996
Of which: Equity-accounted entities[b]	**7,928**	7,828	7,753
Production[a] (net of royalties)			
Liquids (mb/d)	**2,045**	1,927	2,013

Natural gas (mmcf/d)	**7,146**	7,100	7,060
Total hydrocarbons (mboe/d)	**3,277**	3,151	3,230
Of which: Subsidiaries«	**2,007**	1,898	1,882
Equity-accounted entities[c]	**1,270**	1,253	1,348

[a] Because of rounding, some totals may not agree exactly with the sum of their component parts.
[b] Includes BP s share of Rosneft. See Rosneft on page 38 and Supplementary information on oil and natural gas on page 169 for further information.
[c] Includes BP s share of Rosneft. 2013 also includes BP s share of TNK-BP production. See Rosneft on page 38 and Oil and gas disclosures for the group on page 227 for further information.

Total hydrocarbon proved reserves at 31 December 2015, on an oil equivalent basis including equity-accounted entities, decreased by 2% compared with 31 December 2014. The change includes a net increase from acquisitions and disposals of 130mmboe (103mmboe within our subsidiaries, 28mmboe within our equity-accounted entities). Acquisition activity in our subsidiaries occurred in Egypt, Trinidad, the US and the UK, and divestment activity in our subsidiaries occurred in Egypt, Trinidad, the US and the UK. In our equity-accounted entities the most significant item was a purchase in Russia.

Our total hydrocarbon production for the group was 4% higher compared with 2014. The increase comprised a 6% increase (13% increase for liquids and 2% decrease for gas) for subsidiaries and a 1% increase (1% decrease for liquids and 9% increase for gas) for equity-accounted entities.

See Oil and gas disclosures for the group on page 227.

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Upstream

Our strategy is to have a balanced portfolio across the world s key basins, working safely and reliably while maintaining a focus on capital discipline and quality execution to deliver value.

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Operators work on board the floating production, storage and offloading vessel in the Plutão, Saturno, Vénus and Marte fields in Angola.

Our business model and strategy

The Upstream segment is responsible for our activities in oil and natural gas exploration, field development and production, as well as midstream transportation, storage and processing. We also market and trade natural gas, including liquefied natural gas, power and natural gas liquids. In 2015 our activities took place in 25 countries.

With the exception of our 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 over the life of each field.

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 across 12 regions, with support provided by global functions in specialist areas of expertise: technology, finance, procurement and supply chain, human resources and information technology.

The US Lower 48 began operating as a separate onshore business in 2015.

Technologies such as seismic imaging, enhanced oil recovery and big data analytics support our upstream strategy by helping us gain new access, increase recovery and reserves and improve production efficiency. See Our distinctive capabilities on page 16.

We actively manage our portfolio and place 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

developing the resources we believe are likely to add the most value to our portfolio.

Our strategy is to have a balanced portfolio of material, enduring positions in the world s key hydrocarbon basins; to employ capital and execute projects and other activities efficiently; and to operate safely and reliably in every basin to deliver increasing value.

Our strategy is enabled by:

- A continued focus on safety, reliability and the systematic management of risk.
- Prioritizing value over volume, and a continuous focus on executional excellence, managing costs and business delivery.
- Maintaining disciplined investment in a balanced portfolio of opportunities, in deep water, gas value chains, giant fields and unconventionals«.
- Delivering competitive operating cash growth through improvements in efficiency and reliability for both operations and capital investment.
- Strong relationships built on trust, mutual advantage and deep knowledge of the basins where we operate.

Our performance summary

- For upstream safety performance see page 44.
- We achieved an upstream BP-operated plant reliability« of 95%.
- We started up three major upstream projects.

Our exploration function gained access to new potential resources covering almost 8,000km^2 in four countries.

Our divestments generated $0.8 billion in proceeds in 2015.

Upstream profitability ($ billion)

Outlook for 2016

We expect underlying production« to be broadly flat with 2015. The actual reported outcome will depend on the exact timing of project start-ups, divestments, OPEC quotas and entitlement impacts in our production-sharing agreements.

Capital investment is expected to decrease, largely reflecting our commitment to continued capital discipline and the rephasing and refocusing of our activities and major projects where appropriate in response to the current business environment. We will continue to manage our costs down using all levers available to us. These include continuing and expanding the simplification and efficiency efforts started in 2014, continuing to drive deflation into our third-party spend, influencing spend in our non-operated assets, and bringing headcount down to a level that reflects the size of our operations and the current environment.

Oil prices continue to be challenging in the near term.

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Financial performance

			$ million
	2015	2014	2013
Sales and other operating revenues[a]	**43,235**	65,424	70,374
RC profit before interest and tax	**(937)**	8,934	16,657
Net (favourable) unfavourable impact of non-operating items« and fair value accounting effects«	**2,130**	6,267	1,608
Underlying RC profit before interest and tax	**1,193**	15,201	18,265
Capital expenditure and acquisitions	**17,082**	19,772	19,115
BP average realizations«[b]			$ per barrel
Crude oil[c]	**47.78**	93.65	105.38
Natural gas liquids	**20.75**	36.15	38.38
Liquids«	**45.63**	87.96	99.24
			$ per thousand cubic feet
Natural gas	**3.80**	5.70	5.35
US natural gas	**2.10**	3.80	3.07
			$ per barrel of oil equivalent
Total hydrocarbons«	**34.78**	60.85	63.58
Average oil marker prices[d]			$ per barrel
Brent«	**52.39**	98.95	108.66
West Texas Intermediate	**48.71**	93.28	97.99
Average natural gas marker prices			$ per million British thermal units
Henry Hub gas price«[e]	**2.67**	4.43	3.65
			pence per therm
UK National Balancing Point gas price«[d]	**42.61**	50.01	67.99

[a] Includes sales to other segments.
[b] Realizations are based on sales by consolidated subsidiaries« only, which excludes equity-accounted entities.
[c] Includes condensate and bitumen.
[d] All traded days average.
[e] 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 that are derived using differentials or a lagged impact from the Brent crude oil price.

Brent ($/bbl)

Henry Hub ($/mmBtu)

The dated Brent price in 2015 averaged $52.39 per barrel. Prices averaged about $58 during the first half of 2015, but fell sharply during the second half in the face of strong OPEC production growth and rising inventories. Brent prices ended the year near $35.

The Henry Hub First of Month Index price was down by 40%, year-on-year, in 2015 (2014, up by 21%).

The UK National Balancing Point gas price in 2015 fell by 15% compared with 2014 (2014 a decrease of 26% on 2013). This reflected ample supplies in Europe with robust Russian flows, higher LNG cargoes and rising indigenous production. Lower LNG prices in Asia led to a reduction in the price of transacted LNG available for Europe, which contributed to the weakness of European spot prices. For more information on the global energy market in 2015, see page 24.

Financial results

Sales and other operating revenues for 2015 decreased compared with 2014, primarily reflecting significantly lower liquids and gas realizations and lower gas marketing and trading revenues partly offset by higher production. The decrease in 2014 compared with 2013 primarily reflected lower liquids realizations partially offset by higher production in higher-margin areas, higher gas realizations and higher gas marketing and trading revenues.

Replacement cost (RC) loss before interest and tax for the segment included a net non-operating charge of $2,235 million. This is primarily related to a net impairment charge associated with a number of assets, following a further fall in oil and gas prices and changes to other assumptions. See Financial statements Note 4 for further information. Fair value accounting effects had a favourable impact of $105 million relative to management s view of performance.

The 2014 result included a net non-operating charge of $6,298 million, primarily related to impairments associated with several assets, mainly in the North Sea and Angola reflecting the impact of the lower near-term price environment, revisions to reserves and increases in expected decommissioning cost estimates. 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 an unfavourable impact of $244 million from fair value accounting effects.

After adjusting for non-operating items and fair value accounting effects, the decrease in the underlying RC profit before interest and tax compared with 2014 reflected significantly lower liquids and gas realizations, rig cancellation charges and lower gas marketing and trading results partly offset by lower costs including benefits from simplification and efficiency activities and lower exploration write-offs, and higher production.

Compared with 2013 the 2014 result 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. This was partly offset by higher production in higher-margin areas, higher gas realizations and a benefit from stronger gas marketing and trading activities.

Total capital expenditure including acquisitions and asset exchanges in 2015 was lower compared with 2014. This included $100 million capital expenditure before closing adjustments in 2015 relating to the purchase of additional equity in the West Nile Delta concessions in Egypt and $81 million capital expenditure before closing adjustments relating to the purchase of additional equity in the Northeast Blanco and 32-9 concessions in the San Juan basin onshore US.

In total, disposal transactions generated $0.8 billion in proceeds in 2015, with a corresponding reduction in net proved reserves of 20mmboe within our subsidiaries.

The major disposal transaction during 2015 was the sale of our 36% interest in the Central Area Transmission System (CATS) business in the UK North Sea to Antin Infrastructure Partners. More information on disposals is provided in Upstream analysis by region on page 221 and Financial statements Note 4.

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.

In exploration we have reduced capital spending by 50% since 2014 with a focus on prioritizing near-term activity while creating options for longer-term renewal.

New access in 2015

We gained access to new potential resources covering almost 8,000km^2 in four countries (UK (North Sea), Egypt, the US, and Azerbaijan). We acquired a 20% participatory interest in Taas-Yuryakh Neftegazodobycha, a Rosneft subsidiary that will further develop the Srednebotuobinskoye oil and gas condensate field in East Siberia, in November 2015. Related to this, Rosneft and BP will jointly undertake exploration in an adjacent area of mutual interest.

Rosneft and BP have also agreed to jointly explore two additional areas of mutual interest in the prolific West Siberian and Yenisey-Khatanga basins where they will jointly appraise the Baikalovskoye discovery subject to receipt of all relevant consents. This is in addition to the exploration agreement announced in 2014 for an area of mutual interest in the Volga-Urals region of Russia, where Rosneft and BP have commenced joint study work to assess potential non-shale, unconventional tight-oil« exploration prospects.

Exploration success

We participated in two potentially commercial discoveries in Egypt Atoll and Nooros in 2015.

Exploration and appraisal costs

Excluding lease acquisitions, the costs for exploration and appraisal were $1,794 million (2014 $2,911 million, 2013 $4,811 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 26% of exploration and appraisal costs were directed towards appraisal activity. We participated in 29 gross (16.76 net) exploration and appraisal wells in six countries.

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Exploration expense

Total exploration expense of $2,353 million (2014 $3,632 million, 2013 $3,441 million) included the write-off of expenses related to unsuccessful drilling activities, lease expiration or uncertainties around development in Libya ($432 million), Angola ($471 million), the Gulf of Mexico ($581 million) and others ($345 million).

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 2015 decreased by 4% (a decrease of 5% for subsidiaries and an increase of less than 1% for equity-accounted entities) compared with reserves at 31 December 2014.

Proved reserves replacement ratio«

The proved reserves replacement ratio for the Upstream segment in 2015, excluding acquisitions and disposals, was 33% for subsidiaries and equity-accounted entities (2014 31%), 28% for subsidiaries alone (2014 29%) and 76% for equity-accounted entities alone (2014 43%). For more information on proved reserves replacement for the group see page 227.

Upstream reserves

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

	2015	2014	2013
Liquids			million barrels
Crude oil[b]			
Subsidiaries«	**3,560**	3,582	3,798
Equity-accounted entities[c]	**694**	702	729
	4,254	4,283	4,527
Natural gas liquids			
Subsidiaries	**422**	510	551
Equity-accounted entities[c]	**13**	16	16
	435	526	567
Total liquids			
Subsidiaries[d]	**3,982**	4,092	4,349
Equity-accounted entities[c]	**707**	717	745
	4,689	4,809	5,094
Natural gas			billion cubic feet
Subsidiaries[e]	**30,563**	32,496	34,187
Equity-accounted entities[c]	**2,465**	2,373	2,517
	33,027	34,869	36,704
Total hydrocarbons			million barrels of oil equivalent
Subsidiaries	**9,252**	9,694	10,243
Equity-accounted entities[c]	**1,132**	1,126	1,179
	10,384	10,821	11,422

[a] Because of rounding, some totals may not agree exactly with the sum of their component parts.
[b] Includes condensate and bitumen which are not material.
[c] BP s share of reserves of equity-accounted entities in the Upstream segment. During 2015, 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 19 million barrels (21 million barrels at 31 December 2014 and 2013) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC.
[e] Includes 2,359 billion cubic feet of natural gas (2,519 billion cubic feet at 31 December 2014 and 2,685 billion cubic feet at 31 December 2013) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC.

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Developments

We achieved three major project start-ups in 2015: two in Angola and one in Australia. The In Salah Southern Fields project started up in February 2016. In addition to starting up major projects, we made good progress in projects in AGT (Azerbaijan, Georgia, Turkey), the North Sea, Oman and Egypt.

- **Azerbaijan, Georgia, Turkey** we signed agreements to become a shareholder in the Trans Anatolian Natural Gas Pipeline (TANAP), to transport gas from Shah Deniz to markets in Turkey, Greece, Bulgaria and Italy.

- **North Sea** we continued to see high levels of activity, including further progress in the major redevelopment of Quad 204 and approval of the development plans for the Culzean field. We also completed the Magnus life extension project and installed the platform topsides at Clair Ridge.

- **Oman** development of the Khazzan project continued, with 10 rigs in operation by the end of 2015. We also signed a heads of agreement with the government of the Sultanate of Oman to extend the licence area in February 2016.

- **Egypt** we signed final agreements on the West Nile Delta project. We also increased our working interest in both West Nile Delta concessions.

Subsidiaries development expenditure incurred, excluding midstream activities, was $13.5 billion (2014 $15.1 billion, 2013 $13.6 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. These include production from conventional and unconventional (coalbed methane and shale) assets. The principal areas of production are Angola, Argentina, Australia, Azerbaijan, Egypt, Iraq, Trinidad, the UAE, the UK and the US.

With BP-operated plant reliability increasing from around 86% in 2011 to 95% in 2015, efficient delivery of turnarounds and strong infill drilling performance, we expect to keep the average managed base decline through 2016 at around 2% versus our 2014 baseline. Our long-term expectation for managed base decline remains at the 3-5% per annum level we have described in the past.

Production (net of royalties)[a]

	2015	2014	2013
Liquids			thousand barrels per day
Crude oil[b]			

Subsidiaries	**971**	844	789
Equity-accounted entities[c]	**165**	163	294
	1,137	1,007	1,083
Natural gas liquids			
Subsidiaries	**88**	91	86
Equity-accounted entities[c]	**7**	7	8
	95	99	94
Total liquids			
Subsidiaries	**1,060**	936	874
Equity-accounted entities[c]	**172**	170	302
	1,232	1,106	1,176
Natural gas		million cubic feet per day	
Subsidiaries	**5,495**	5,585	5,845
Equity-accounted entities[c]	**456**	431	415
	5,951	6,016	6,259
Total hydrocarbons	thousand barrels of oil equivalent per day		
Subsidiaries	**2,007**	1,898	1,882
Equity-accounted entities[c]	**251**	245	374
	2,258	2,143	2,256

[a] Because of rounding, some totals may not agree exactly with the sum of their component parts.
[b] Includes condensate and bitumen which are not material.
[c] Includes BP s share of production of equity-accounted entities in the Upstream segment.

Our Upstream project pipeline

Key: Oil Gas
*BP operated

Project	Location	Type
2015 start-ups		
Kizomba Satellites Phase 2	Angola	Deepwater
Greater Plutonio Phase 3*	Angola	Deepwater
Western Flank Phase A	Australia	LNG
Expected start-ups 2016-2020		

Project	Location	Type
Expected start-ups 2017-2020		
Design and appraisal phase		
Angelin	Trinidad	LNG
Atoll	Egypt	Conventional
B18	Angola	Deepwater
Platina*		
	Gulf of Mexico	Deepwater

Projects currently under construction

Angola LNG	Angola	LNG
In Amenas compression	North Africa	Conventional
In Salah Southern Fields[a]	North Africa	Conventional
Point Thomson	Alaska	Conventional
Quad 204*	North Sea	Conventional
Thunder Horse water injection*	Gulf of Mexico	Deepwater
Clair Ridge*	North Sea	Conventional
Juniper	Trinidad	LNG
Oman Khazzan*	Middle East	Tight
Persephone	Asia Pacific	LNG
Thunder Horse South expansion*	Gulf of Mexico	Deepwater
West Nile Delta Taurus/Libra*	Egypt	Conventional
Culzean	North Sea	High pressure
Shah Deniz Stage 2*	Azerbaijan	Conventional
Taas-Yuryakh expansion	Russia	Conventional
West Nile Delta Giza/ Fayoum/Raven*	Egypt	Conventional
Western Flank Phase B	Australia	Conventional
Mad Dog Phase 2*		
Snadd*	North Sea	Conventional
Tangguh expansion*	Asia Pacific	LNG
Trinidad onshore compression	Trinidad	LNG
Trinidad offshore compression	Trinidad	LNG
Vorlich*	North Sea	Conventional

Beyond 2020

We have an additional 35-40 projects in the pipeline for post-2020 start-up.

Mix of resource types across conventional oil, deepwater oil, conventional gas and unconventionals.

Broad geographic reach.

Range of development types, from new to producing fields where we can use existing infrastructure.

[a] Started up in February 2016.

Our total hydrocarbon production for the segment in 2015 was 5.4% higher compared with 2014. The increase comprised a 5.7% increase (13.2% increase for liquids and 1.6% decrease for gas) for subsidiaries and a 2.4% increase (1.2% increase for liquids and 5.8% increase for gas) for equity-accounted entities compared with 2014. For more information on production see Oil and gas disclosures for the group on page 227.

In aggregate, underlying production was flat versus 2014.

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

Our integrated supply and trading function markets and trades our own and third-party natural gas (including LNG), power and NGLs. This provides us with routes into liquid markets for the gas we produce and generates margins and fees from selling physical products and derivatives to third parties, together with income from asset optimization and trading. This means we have a single interface with gas trading markets and one consistent set of trading compliance and risk management processes, systems and controls.

Our upstream marketing and trading activity primarily takes place in the US, Canada and Europe and supports group LNG activities, managing market price risk and creating incremental trading opportunities through the use of commodity derivative contracts. It also enhances margins and generates fee income from sources such as the management of price risk on behalf of third-party customers.

Our trading financial risk governance framework is described in Financial statements Note 28 and the range of contracts used is described in Glossary commodity trading contracts on page 256.

Unlocking energy potential

BP has invested in Egypt for half a century. And in recent years, it has been a key location for BP discoveries. Our ongoing investment and exploration activities are helping to unlock energy potential in the area.

In March we made a gas discovery 6,400 metres below sea level in the North Damietta offshore area. We are working with the Egyptian government to accelerate the development of the Atoll discovery.

The discovery is in line to become our next major project in Egypt after completion of our West Nile Delta project.

Building a pipeline of future growth opportunities.

« Defined on page 256.

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Downstream

We continued to improve our personal and process safety and delivered strong operations and marketing performance, contributing to record replacement cost profit before interest and tax.

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The Cherry Point refinery processes crude oil sourced from Alaska, mid-continent US and Canada and has a capacity of 234,000 barrels per day.

Our business model and strategy

The Downstream segment has global manufacturing and marketing operations. It 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 our 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, sells and distributes products, that are produced mainly using proprietary BP technology, and are then used by others to make essential consumer products such as paint, plastic bottles and textiles. We also license our technologies to third parties.

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 that meet our customers needs.

Our strategy focuses on a quality portfolio that aims to lead the industry, as measured by net income per barrel«, with improving returns and growing operating cash flow«. 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 continue to build a top-quartile refining business by having a competitively advantaged portfolio underpinned by operational excellence that helps to reduce exposure to margin volatility. In petrochemicals we seek to sustainably improve earnings potential and make the business more resilient to a bottom of cycle environment through portfolio repositioning, improved operational performance and efficiency benefits.

Fuels and lubricants marketing we invest in higher-returning businesses with reliable cash flows and growth potential.

Portfolio quality we maintain our focus on quality by high-grading of assets combined with capital discipline.

Simplification and efficiency we are embedding a culture of simplification and efficiency to support performance improvement and make our businesses even more competitive.

Disciplined execution of our strategy is helping improve our underlying performance and create a more resilient business that is better able to withstand external environmental impacts. This is with the aim of ensuring Downstream remains a reliable source of cash flow for BP.

Our performance summary

For Downstream safety performance see page 45.

We have delivered record replacement cost profit before interest and tax« and pre-tax returns« this year, demonstrating that we are creating a more resilient Downstream business.

We delivered strong availability and operational performance across our refining portfolio and year-on-year improvement in utilization.

We commenced the European launch of our BP fuels with *ACTIVE* technology in Spain, which are designed to remove dirt and protect car engines.

We announced the agreement to restructure our German refining joint operation« with Rosneft.

We halted operations at Bulwer refinery in Australia.

In Air BP we completed the integration of Statoil Fuel and Retail s aviation business which added more than 70 airports to our global network.

In our lubricants business we launched *Castrol s Nexcel*, an innovative automotive oil-change technology.

We completed start-up of the Zhuhai 3 plant in China the world s largest single train purified terephthalic acid (PTA) unit.

Our simplification and efficiency programmes contributed to material progress in lowering cash costs«. These programmes include right-sizing the Downstream organization, implementing site-by-site improvement plans to deliver manufacturing efficiency in refining and petrochemicals, and focusing on third-party costs.

Downstream profitability ($ billion)

See Financial performance on page 35 for the main factors influencing downstream profit.

Outlook for 2016

We anticipate a weaker refining environment.

We expect the financial impact of refinery turnarounds to be higher than 2015 as a result of increased turnaround activity.

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Financial performance

			$ million
	2015	2014	2013
Sale of crude oil through spot and term contracts	**38,386**	80,003	79,394
Marketing, spot and term sales of refined products	**148,925**	227,082	258,015
Other sales and operating revenues	**13,258**	16,401	13,786
Sales and other operating revenues[a]	**200,569**	323,486	351,195
RC profit (loss) before interest and tax[b]			
Fuels	**5,858**	2,830	1,518
Lubricants	**1,241**	1,407	1,274
Petrochemicals	**12**	(499)	127
	7,111	3,738	2,919
Net (favourable) unfavourable impact of non-operating items« and fair value accounting effects«			
Fuels	**137**	389	712
Lubricants	**143**	(136)	(2)
Petrochemicals	**154**	450	3
	434	703	713
Underlying RC profit (loss) before interest and tax[b]			
Fuels	**5,995**	3,219	2,230
Lubricants	**1,384**	1,271	1,272
Petrochemicals	**166**	(49)	130
	7,545	4,441	3,632
Capital expenditure and acquisitions	**2,109**	3,106	4,506

[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 2015 were lower compared with 2014 due to lower crude prices. Similarly, the decrease in 2014, compared with 2013 primarily was due to falling crude prices.

Replacement cost (RC) profit before interest and tax for the year ended 31 December 2015 included a net operating charge of $590 million, mainly relating to restructuring charges. 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 the 2013 result 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 $156 million, compared with a favourable impact of $867 million in 2014 and an unfavourable impact of $178 million in 2013.

After adjusting for non-operating items and fair value accounting effects, underlying RC profit before interest and tax of $7,545 million in 2015 was a record for Downstream.

Our fuels business

The fuels strategy focuses primarily on fuels value chains (FVCs). This includes building a top-quartile and focused refining business through operating reliability, feedstock and location advantage and efficiency improvements to our already competitively advantaged portfolio.

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.

In January 2016 we announced that we signed definitive agreements to dissolve our German refining joint operation with our partner Rosneft. The restructuring will refocus our refining business in the heart of Europe and is in line with our drive for greater simplification and efficiency.

We continue to grow our fuels marketing businesses, including retail, through differentiated marketing offers and key partnerships. We partner with leading retailers, creating distinctive offers that aim to deliver good returns and reliable profit and cash generation (see page 13).

Underlying RC profit before interest and tax was higher compared with 2014 reflecting a strong refining environment, improved refining margin optimization and operations, and lower costs from simplification and efficiency programmes. Compared with 2013, the 2014 result was higher, 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.

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	**2015**	2014	2013
US North West	Alaska North Slope	**24.0**	16.6	15.2
US Midwest	West Texas Intermediate	**19.0**	17.4	21.7
Northwest Europe	Brent«	**14.5**	12.5	12.9
Mediterranean	Azeri Light	**12.7**	10.6	10.5
Australia	Brent	**15.4**	13.5	13.4
BP RMM		**17.0**	14.4	15.4

BP refining marker margin ($/bbl)

The average global RMM in 2015 was $17.0/bbl, $2.6/bbl higher than in 2014, and the second highest on record (after 2012). The increase was driven by higher margins on gasoline as a result of increased demand in a low oil price environment and persistent refinery outages in the US.

Refining

At 31 December 2015 we owned or had a share in 13 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 225.

In 2015, refinery operations were strong, with Solomon refining availability« sustained at around 95% and utilization rates of 91% for the year. Overall refinery throughputs in 2015 were flat compared to 2014, with reduced throughput from ceasing refining operations at Bulwer refinery, offset by increased throughput at the Whiting and Kwinana refineries.

	2015	2014	2013
Refinery throughputs[a]	thousand barrels per day		
US[b]	**657**	642	726
Europe	**794**	782	766
Rest of world[b]	**254**	297	299
Total	**1,705**	1,721	1,791
			%
Refining availability	**94.7**	94.9	95.3
Sales volumes	thousand barrels per day		
Marketing sales[c]	**2,835**	2,872	3,084
Trading/supply sales[d]	**2,770**	2,448	2,485
Total refined product sales	**5,605**	5,320	5,569
Crude oil[e]	**2,098**	2,360	2,142
Total	**7,703**	7,680	7,711

[a] Refinery throughputs reflect crude oil and other feedstock volumes.
[b] Bulwer refinery in Australia ceased refining operations in 2015. The Texas City and Carson refineries in the US 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. 87,000 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 excellence in operational and transactional processes and deliver compelling customer offers in the various markets where we operate. In early 2016 we agreed the disposal of our Amsterdam oil terminal. We also announced our intention to enter into joint ventures« on certain midstream assets in North America and Australia to increase our competitiveness and enable growth in these regions.

We supply fuel and related retail services to consumers through company-owned and franchised retail sites, as well as other channels, including dealers 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]	**2015**	2014	2013
US	**7,000**	7,100	7,700
Europe	**8,100**	8,000	8,000
Rest of world	**2,100**	2,100	2,100
Total	**17,200**	17,200	17,800

[f] Reported to the nearest 100. 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. In addition 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. This year we began rolling out our new BP fuels with *ACTIVE* technology in Spain and we plan to continue this roll-out in additional markets in 2016.

Supply and trading

Our integrated supply and trading function is responsible for delivering value across the overall crude and oil products supply chain. This structure enables our downstream businesses to maintain a single interface with oil trading markets and operate with one set of trading compliance and risk management processes, systems and controls. It has a two-fold purpose:

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First, it seeks to identify the best markets and prices for our crude oil, source optimal raw materials for our refineries and provide competitive supply for our marketing businesses. We will often sell our own crude and purchase alternative crudes from third parties for our refineries where this will provide incremental margin.

Second, it 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 combination with rights to access storage and transportation capacity, this allows it to access advantageous price differences between locations and time periods, and to arbitrage between markets.

The function has trading offices in Europe, North America 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.

Our trading financial risk governance framework is described in Financial statements Note 28 and the range of contracts used is described in Glossary commodity trading contracts on page 256.

Aviation

Air BP s strategic aim is to continue to hold strong positions in our core locations of Europe and the US, while expanding our 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 more than 430,000 barrels per day and we added more than 70 airports to our global network with the acquisition of Statoil Fuel & Retail s aviation business.

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 that we believe provides us with significant competitive advantage. In technology, we apply our expertise to create differentiated, premium 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 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 was higher than 2014 and 2013. The 2015 result reflected strong performance in growth markets and premium brands and lower costs from simplification and efficiency programmes. These factors contributed to around a 20% year-on-year improvement in results, which was partially offset by adverse foreign exchange impacts. The 2014 result benefited from improved margins across the portfolio, offset by adverse foreign exchange impacts.

Our petrochemicals business

Our petrochemicals strategy is to improve our earnings potential and make the business more resilient to a bottom-of-cycle environment. We develop proprietary technology to deliver leading cost positions compared with 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 reposition our portfolio, improve operating performance and create efficiency benefits. We are taking steps to significantly improve the resilience of the business to a bottom-of-cycle environment by:

- 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.
- Delivering value through simplification and efficiency programmes.

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 in their domestic market. We are licensing our distinctive technologies, including recently announced licensing agreements for our latest generation PTA technology in Oman and China.

In 2015 the petrochemicals business delivered a higher underlying RC profit before interest and tax compared with 2014 and 2013. The result reflected improved operational performance and benefits from our simplification and efficiency programmes leading to lower costs. Compared with 2013, the 2014 result was lower, reflecting a continuation of the weak margin environment, particularly in the Asian aromatics sector, and unplanned operational events.

Our petrochemicals production of 14.8 million tonnes in 2015 was higher than 2014 and 2013 (2014 14.0mmte, 2013 13.9mmte), with the low margin environment in 2014 and 2013 driving reduced output.

In 2015, our Zhuhai 3 PTA plant in China was fully commissioned adding 1.25 million tonnes of production capacity to our petrochemicals portfolio. During the year we also shut down older capacity of certain units in the US and Asia.

We are upgrading our PTA plants at Cooper River in South Carolina, US 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.

We announced in January 2016 that we had reached an agreement to sell our Decatur petrochemicals complex in Alabama, US, as part of our strategy to refocus our global petrochemicals business for long-term growth.

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Rosneft

Rosneft is the largest oil company in Russia, with a strong portfolio of existing and future opportunities.

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Taas-Yuryakh central processing facility at the Srednebotuobinskoye oil and gas field during the Siberian winter.

BP and Rosneft

BP s 19.75% 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 is positioned to contribute to Rosneft s strategy implementation through collaboration on technology and best practice.

We 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.

2015 summary

In the current environment Rosneft continues to deliver solid operational and financial performance, demonstrating the resilience of its business model.

BP received $271 million, net of withholding taxes, in July representing our share of Rosneft s dividend of 8.21 Russian roubles per share for 2014.

In 2015 Rosneft met all its debt service obligations and increased total hydrocarbon production by 1%.

Bob Dudley serves on the Rosneft Board of Directors, and its Strategic Planning Committee.

A second BP nominee, Guillermo Quintero, was elected to Rosneft s Board of Directors at Rosneft s annual general meeting in June 2015 and was subsequently elected to its HR and Remuneration Committee.

US and EU sanctions remain in place on certain Russian activities, individuals and entities, including Rosneft.

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: West Siberia, East Siberia, Timan-Pechora, Volga-Urals, North Caucasus, the continental shelf of the Arctic Sea, and the Far East.

BP purchased a 20% participatory interest in Taas-Yuryakh Neftegazodobycha, a Rosneft subsidiary that will further develop the Srednebotuobinskoye oil and gas condensate field in East Siberia. Related to this, Rosneft and BP will jointly undertake exploration in an adjacent area of mutual interest. BP s interest in Taas-Yuryakh Neftegazodobycha is reported in the Upstream segment.

Rosneft and BP have also agreed to jointly explore two additional areas of mutual interest in the prolific West Siberian and Yenisey-Khatanga basins, where they will jointly appraise the Baikalovskoye discovery subject to receipt of all relevant consents. This is in addition to the exploration agreement announced in 2014 for an area of mutual interest in the Volga-Urals region of Russia, where Rosneft and BP have commenced joint study work to assess potential non-shale, unconventional tight-oil« exploration prospects.

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.

Rosneft continued to optimize its budget and to focus on new upstream projects, including the development of the Labaganskoye, Suzun and East Messoyakha fields. It also signed preliminary contracts for the Russkoye, Kuyumba, Yurubcheno-Tokhomskoye and East Messoyakha fields to deliver oil to the Transneft pipeline system.

Rosneft s estimated hydrocarbon production reached an annual record in 2015. This was due to a ramp-up in drilling, optimization of well performance and the application of modern technologies such as multistage fracturing, dual completion and bottomhole treatment. In 2015 estimated gas production increased by around 10% compared with 2014, primarily driven by greenfield start-ups and commissioning of new wells.

Downstream

Rosneft is the leading Russian refining company based on throughputs. It owns and operates 10 refineries in Russia. Rosneft continued to implement the modernization programme for its Russian refineries in 2015 to significantly upgrade and expand refining capacity.

As at 31 December 2015, Rosneft owned and operated more than 2,500 retail service stations in Russia and abroad. This includes BP-branded sites acquired as part of the TNK-BP acquisition in 2013 that, under a licence agreement with BP, continue to operate under the BP brand. Downstream operations also include jet fuel, bunkering, bitumen and lubricants.

On 15 January 2016 BP and Rosneft announced that they had signed definitive agreements to dissolve the German refining joint operation« Ruhr Oel GmbH (ROG). The restructuring, which is expected to be completed in 2016, will result in Rosneft taking ownership of ROG s interests in the Bayernoil, MiRO Karlsruhe and PCK Schwedt refineries. In exchange, BP will take sole ownership of the Gelsenkirchen refinery and the solvent production facility DHC Solvent Chemie.

Rosneft refinery throughputs in 2015 amounted to 1,966mb/d (2014 2,027mb/d, 2013 1,818mb/d).

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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, representing BP s 19.75% share of the profit or loss of Rosneft, as adjusted 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. See Financial statements Note 16 for further information.

			$ million
	2015[a]	2014	2013[b]
Profit before interest and tax[c d]	**1,314**	2,076	2,053
Inventory holding (gains) losses«	**(4)**	24	100
RC profit before interest and tax	**1,310**	2,100	2,153
Net charge (credit) for non-operating items«		(225)	45
Underlying RC profit before interest and tax«	**1,310**	1,875	2,198
Average oil marker prices			$ per barrel
Urals (Northwest Europe CIF)	**50.97**	97.23	107.38

[a] The operational and financial information of the Rosneft segment for 2015 is based on preliminary operational and financial results of Rosneft for the three months ended 31 December 2015. 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 $16 million (2014 $25 million, 2013 $5 million) of foreign exchange losses arising on the dividend received.

Market price

The price of Urals delivered in North West European (Rotterdam) averaged $50.97/bbl in 2015, $1.42/bbl below dated Brent«. The differential to Brent narrowed marginally from -$1.72/bbl in 2014 as stronger demand from European refineries offset the impact of increased supplies of competing medium sour crude from the Middle East.

Financial results

Replacement cost (RC) profit before interest and tax for the segment for the year ended 31 December 2015 did not include any non-operating items, whereas the 2014 result included a non-operating gain of $225 million, relating to Rosneft s sale of its interest in the Yugragazpererabotka joint venture«.

After adjusting for non-operating items, the decrease in the underlying RC profit before interest and tax compared with 2014 reflected lower oil prices, foreign exchange, and comparatively favourable duty lag effects. The rouble weakened against the US dollar during 2015. This impacts both Rosneft s earnings in roubles and BP s share of the Rosneft result when it is translated to US dollars. Compared with 2013, the 2014 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 16 and 31 for other foreign exchange effects.

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Rosneft s operations in West Siberia.

Balance sheet

			$ million
	2015	2014	2013
Investments in associates«[e] (as at 31 December)	**5,797**	7,312	13,681

Production and reserves

	2015[a]	2014	2013[f]
Production (net of royalties) (BP share)[c]			
Liquids« (mb/d)			
Crude oil[g]	**809**	816	643
Natural gas liquids	**4**	5	7
Total liquids	**813**	821	650
Natural gas (mmcf/d)	**1,195**	1,084	617
Total hydrocarbons« (mboe/d)	**1,019**	1,008	756
Estimated net proved reserves[h] (net of royalties) (BP share)			
Liquids (million barrels)			
Crude oil[g]	**4,823**	4,961	4,860
Natural gas liquids	**47**	47	115
Total liquids[i]	**4,871**	5,007	4,975
Natural gas[j] (billion cubic feet)	**11,169**	9,827	9,271
Total hydrocarbons (mmboe)	**6,796**	6,702	6,574

[e] See Financial statements Note 16 for further information.

[f] 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 230 and 231.

[g] Includes condensate.

[h] Because of rounding, some totals may not agree exactly with the sum of their component parts.

[i] Includes 70 million barrels of crude oil in respect of the 1.27% non-controlling interest in Rosneft held assets in Russia including 28 million barrels held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

[j] Includes 129 billion cubic feet of natural gas in respect of the 0.23% non-controlling interest in Rosneft held assets in Russia including 5 billion cubic feet held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

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Other businesses

and corporate

Comprises our renewables business, shipping, treasury and corporate activities including centralized functions.

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At our Tropical BioEnergia plant in Brazil we process sugar cane to produce biofuels.

Financial performance

			$ million
	2015	2014	2013
Sales and other operating revenues[a]	**2,048**	1,989	1,805
RC profit (loss) before interest and tax	**(1,768)**	(2,010)	(2,319)
Net (favourable) unfavourable impact of non-operating items«	**547**	670	421
Underlying RC profit (loss) before interest and tax«	**(1,221)**	(1,340)	(1,898)
Capital expenditure and acquisitions	**340**	903	1,050

[a] Includes sales to other segments.

The replacement cost (RC) loss before interest and tax for the year ended 31 December 2015 was $1.8 billion (2014 $2.0 billion, 2013 $2.3 billion). The 2015 result included a net charge for non-operating items of $547 million (2014 $670 million, 2013 $421 million).

After adjusting for these non-operating items, the underlying RC loss before interest and tax for the year ended 31 December 2015 was $1.2 billion, similar to prior year (2014 $1.3 billion, 2013 $1.9 billion).

Renewable energy

BP has the largest operated renewables business among our oil and gas peers. Our activities are focused on biofuels and onshore wind.

Biofuels business model and strategy

Biofuels can be blended into traditional transport fuels without significant engine modifications to existing fuel-delivery systems. BP is working to produce biofuels that are low cost, low carbon, scalable and competitive without subsidies.

Our main activity is in Brazil, where we operate three sugar cane mills producing bioethanol and sugar, and exporting power made from sugar cane waste to the local grid. We use our expertise and technology capabilities to drive continuing improvements in operational efficiency. Our strategy is enabled by:

- **Safe and reliable operations** continuing to drive improvements in personal, process and transport safety.

- **Competitive sourcing** concentrating our efforts in Brazil, which has one of the most cost-competitive biofuel feedstocks currently available in the world.

- **Low carbon** producing bioethanol supported by low-carbon power generated from burning sugar cane waste. These processes reduce life-cycle GHG emissions by around 70% compared with gasoline.

- **Domestic and international markets** selling bioethanol domestically in Brazil and also to international markets such as the US and Europe through our integrated supply and trading function.

We are also investing in the development and commercialization of biobutanol, in conjunction with our partner DuPont. Compared with other biofuels, biobutanol has the potential to be blended with fuels in higher proportions, and be easier to transport, store and manage. We are also investigating a number of chemical applications for this advanced biofuel.

Our performance summary

- We have reduced our recordable injury frequency by more than 60% since the acquisition of Companhia Nacional de Açúcar e Álcool in 2011. For more information, see Safety on page 45.

- We increased our production of ethanol equivalent by 47% compared with 2014 and generated 677GWh of power for Brazil s national grid.

- We divested our interest in Vivergo Fuels a UK-based joint venture« producing bioethanol from wheat in May 2015.

- We are improving our agricultural operational performance with a 36% increase in cane harvester efficiency relative to 2014, and in 2015, we farmed a total planted area of 127,000 hectares.

BP Brazil biofuels production

(million litres of ethanol equivalent)

Wind

We are among the top wind energy producers in the US. Our focus is on safe operations and optimizing performance.

BP holds interests in 16 onshore wind farms in the US, and BP is the operator of 14 of these. Our net generating capacity« from this portfolio, based on our financial stake, was 1,556 megawatts (MW) of electricity at 31 December 2015.

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BP also runs two wind farms in our refinery sites in the Netherlands, operating on a much smaller scale and managed by our Downstream segment, with 32MW of generating capacity.

Our net share of wind generation for 2015 was 4,424GWh, compared with 4,617GWh a year ago. Lower power generation was primarily a result of less windy weather across the US in 2015.

See our Sustainability Report or *bp.com/renewables* for additional information on our renewable energy activities.

Shipping

The primary purpose of BP s shipping and chartering activities is the safe 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 2015, our fleet included four vessels supporting operations in Alaska, 44 BP-operated and 40 time-chartered vessels for our deep-sea, international oil and gas shipping operations. In addition 28 deep-sea oil tankers and six LNG tankers are on order and planned for delivery into the BP-operated fleet between 2016 and 2019. The first of these new vessels, the *British Respect* oil tanker, was formally named at a ceremony in November.

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, 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 28.

Insurance

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. Some risks are insured with third parties and reinsured by group insurance companies. 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 $1.2 billion in 2016.

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BP shipping reached a centenary of maritime achievement in April 2015.

Gulf of Mexico oil spill

BP reached agreements resolving the largest remaining liabilities.

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Shrimpers off the coast of Grand Isle in Louisiana.

Key events

BP reached agreements in principle with the United States federal government and five Gulf states in July to settle all federal and state claims arising from the Deepwater Horizon accident and oil spill (the incident). In addition, BP also settled the vast majority of claims made by local government entities.

The United States lodged a proposed Consent Decree with the district court in October to resolve all United States and Gulf states natural resource damage claims and all Clean Water Act penalty claims. At the same time, BP entered a Settlement Agreement with the Gulf states for economic, property and other losses.

The proposed Consent Decree and the Settlement Agreement are conditional on each other and neither will become effective unless the court provides final approval of the Consent Decree.

The final submission deadline for claims under the 2012 Plaintiffs Steering Committee settlements was 8 June 2015.

By the end of 2015, the cumulative pre-tax income statement charge as a result of the incident amounted to $55.5 billion. This excludes amounts that BP does not consider possible to measure reliably at this time.

Federal and state settlements

On 2 July 2015 BP announced that BP Exploration & Production Inc. (BPXP) had reached agreements in principle to settle all federal and state claims arising from the incident. The United States is expected to file a motion with the court to enter the Consent Decree as a final settlement around the end of March, which the court will then consider. Subject to final court approval, payments under the terms of the agreements will be made at a rate of around $1.1 billion a year for the majority of the 18-year payment period.

See Legal proceedings on page 237 for further details including a summary of what is not covered by the proposed Consent Decree and the Settlement Agreement. For additional details on the financial impacts see Financial statements Note 2.

Plaintiffs Steering Committee settlements

The Plaintiffs Steering Committee (PSC) was established to act on behalf of individual and business plaintiffs in the multi-district litigation proceedings in federal court in New Orleans (MDL 2179). In 2012 BP reached settlements to resolve the substantial majority of legitimate individual and business claims and medical claims stemming from the incident. Approximately $2.3 billion was paid out under the PSC settlements during 2015. Claims continue to be assessed and paid.

The medical benefits class action settlement provides for claims to be paid to qualifying class members. The deadline for submitting claims under the settlement was 12 February 2015.

Securities litigation and other legal 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 July 2016.

In MDL 2179, claims by individuals and businesses that opted out of the PSC settlements or whose claims were excluded from them, including claims for recovery of losses allegedly resulting from the 2010 federal deepwater drilling moratoria and the related permitting processes, are continuing.

BP is subject to additional legal proceedings in connection with the incident. For more information see Legal proceedings on page 237.

Environmental restoration

In April 2011 BP committed to provide $1 billion in early restoration funding to expedite recovery of natural resources injured as a result of the incident. By the end of 2015 BP had provided approximately $762 million to support restoration projects, with the remaining $238 million expected to be funded in 2016. The federal and state settlements referred to above include more than $7 billion to resolve all natural resource damage claims, which is in addition to this $1 billion.

In May 2010 BP committed $500 million over 10 years to fund independent scientific research through the Gulf of Mexico Research Initiative. BP had contributed $278 million to the programme by the end of 2015.

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

Process safety and ethics monitors

Two independent monitors an ethics monitor and a process safety monitor were appointed under the terms of the criminal plea agreement BP reached with the US government in 2012. Under the terms of the agreement, BP is taking additional actions to further enhance ethics and compliance and the safety of its drilling operations in the Gulf of Mexico.

The ethics monitor delivered an initial report early in 2015. He delivered a second report later in the year under a separate administrative agreement with the US Environmental Protection Agency. Recommendations from the two reports largely relate to BP s ethics and compliance programme and code of conduct, including its implementation and enforcement. The recommendations have been agreed and BP is now in the process of implementing them. The ethics monitor is meanwhile conducting a follow-up review as the next phase of his engagement.

The process safety monitor reviews and provides recommendations concerning BPXP s process safety and risk management procedures for deepwater drilling in the Gulf of Mexico. BPXP is the BP group company that conducts exploration and production operations in the Gulf of Mexico. The process safety monitor also submitted a report in 2015. Following discussions between BPXP, the process safety monitor and the US Department of Justice, the recommendations have now been finalized and implementation by BPXP is underway.

Financial update

The group income statement for 2015 includes a pre-tax charge of $12.0 billion in relation to the incident. The charge for the year reflects the amounts provided for the proposed Consent Decree; the Settlement Agreement with the five Gulf states and local government claims as described above; additional provisions made for business economic loss claims under the PSC settlement and other items. As at 31 December 2015, the total cumulative charges recognized to date amounted to $55.5 billion. The total amounts that will ultimately be paid by BP in relation to all the obligations relating to the incident are subject to 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. There continues to be uncertainty regarding the extent and timing of the remaining costs and liabilities not covered by the proposed Consent Decree and Settlement Agreement, including:

- Claims asserted in civil litigation, including any further litigation by parties excluded from, or parties who opted out of, the PSC settlement, and the private securities litigation pending in MDL 2185.

- The cost of business economic loss claims under the PSC settlement not yet processed or processed but not yet paid (except where an eligibility notice has 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).

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

Payments made out of the $20-billion Deepwater Horizon Oil Spill Trust (the Trust) during 2015 totalled $3.2 billion. As at 31 December 2015, the aggregate cash balances in the Trust and the associated qualified settlement funds amounted to $1.4 billion, nearly all of which was committed to specific purposes including the seafood compensation fund and natural resource damage early restoration projects. As of January 2016, payments in respect of claims and other costs previously funded from the Trust are now being made by BP.

More details regarding the impacts and uncertainties relating to the Gulf of Mexico oil spill can be found in Risk factors on page 53, Legal proceedings on page 237 and Financial statements Note 2.

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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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At our US Whiting refinery we have invested in new equipment to reduce air emissions and implemented a monitoring system to provide air quality information to the local community.

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 2015 we had completed all 26 recommendations from BP s internal investigation regarding the Deepwater Horizon accident, the Bly Report.

52% of the 353 million hours worked by BP in 2015 were carried out by contractors.

Process safety events

(number of incidents)

Recordable injury frequency

(workforce incidents per 200,000 hours worked)

[a] API and OGP 2015 data reports are not available until May 2016.

Additional information on our safety, environmental and social performance is available in our sustainability report. Case studies, country reports and an interactive tool for health, safety and environmental data can be found at *bp.com/sustainability*

Group safety performance

In 2015 BP reported one workforce fatality in Turkey that occurred when a ceiling collapsed during renovations at a recently acquired retail site. We deeply regret the loss of this life and continue to focus efforts on eliminating injuries and fatalities in our workplaces.

Personal safety performance

	2015	2014	2013
Recordable injury frequency (group)[b]	**0.24**	0.31	0.31
Day away from work case frequency[c] (group)[b]	**0.061**	0.081	0.070
Severe vehicle accident rate[d]	**0.112**	0.132	0.122

[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

		2015	2014	2013
Tier 1 process safety events«		**20**	28	20
Tier 2 process safety events		**83**	95	110
Loss of primary containment	number of all incidents[e]	**235**	286	261
Loss of primary containment	number of oil spills[f]	**146**	156	185

Number of oil spills to land and water	**55**	63	74
Volume of oil spilled (thousand litres)	**432**	400	724
Volume of oil unrecovered (thousand litres)	**142**	155	261

[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) recommended practice 754. These include tier 1 process safety events, defined as a loss of primary containment causing harm to a member of the workforce, costly damage to equipment or exceeding defined quantities. Tier 2 events are those of lesser consequence than tier 1.

We seek to record all losses of primary containment regardless of the volume of the release, and to report externally on losses over a severity threshold. These include unplanned or uncontrolled releases from pipes, containers or vehicles within our operational boundary, excluding releases of non-hazardous substances such as water.

We have seen improvements in our process safety performance over the past five years. This has been true across our upstream and downstream businesses, with fewer tier 1 process safety events, fewer leaks and spills and fewer recordable injuries. At the same time, the reliability of our rigs and refineries has improved. We believe this shows that the rigour needed to produce safe operations tends also to produce reliable operations. We will maintain our focus on systematic safety management, including self-verification and testing the effectiveness of our risk mitigation measures.

Our figures for loss of primary containment in 2014 and 2015 include increased reporting due to the introduction of enhanced automated monitoring for remote sites in our US Lower 48 business. Using a like-for-like approach with prior years reporting, our 2015 loss of primary containment figure is 208 (2014 246).

Managing safety

We are working to continuously improve personal and process safety and operational risk management across BP. Process safety is the application of good design and engineering principles, as well as robust operating and

« Defined on page 256.

maintenance practices, to avoid accidents. Our approach builds on our experience, including learning from incidents, operations audits, annual risk reviews and sharing lessons learned with our industry peers.

BP-operated businesses are responsible for identifying and managing operating risks and bringing together people with the right skills and competencies to address them. They are required to carry out self-verification and are also subject to independent scrutiny and assurance. Our safety and operational risk team works alongside BP-operated businesses to provide oversight and technical guidance, while our group audit team visits sites on a risk-prioritized basis, including third-party drilling rigs, to check how they are managing risks.

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 51 and SEEAC s report on page 71.

Operating management system

BP s OMS is a group-wide framework designed to help us manage risks and drive performance improvements in BP-operated businesses. 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.

We review and amend our group requirements within OMS from time to

time to reflect BP s priorities and experience or changing external regulations. Any 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 activities. All businesses covered by OMS undertake an annual performance improvement cycle and assess alignment with the applicable requirements of the OMS framework. Recently acquired operations need to transition to OMS. See page 45 for information about contractors and joint arrangements.

Security and crisis management

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

Cyber attacks present a risk to the security of our information, IT systems and operations. We maintain a range of defences to help prevent and respond to this threat, including a 24-hour monitoring centre in the US and employee cyber awareness programmes.

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 47 for information on BP s approach to oil spill preparedness and response.

Upstream safety

Key safety metrics 2011-2015

Safety performance

		2015	2014	2013
Recordable injury frequency		**0.21**	0.23	0.32
Day away from work case frequency		**0.034**	0.051	0.068
Loss of primary containment incidents	number	**153**	187	143

Safer drilling

Our global wells organization is responsible for planning and executing 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

We have completed all 26 recommendations made by BP s investigation into the Deepwater Horizon accident, the Bly Report, aimed at further reducing risk across our global drilling activities.

Our group audit team has verified closure of the recommendations.

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

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. He also provided process safety observations and his views on the organizational effectiveness and culture of the global wells organization.

Over the period of his appointment Mr Sandlin met regularly with wells organization leadership and reviewed the standards and practices developed to complete the recommendations. He made three visits to each of the regional wells teams with active drilling operations, meeting key personnel and drilling contractors on site.

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Mr Sandlin s engagement came to a close in February 2016 after he reported to SEEAC that all 26 Bly Report recommendations had been closed out to his satisfaction. He stated that the idea of safety as a top priority is firmly ingrained throughout the global wells organization and noted an increase in the degree of rigour and engagement at all levels. Mr Sandlin recommended the organization build on the foundations established by the recommendations and maintain its focus on continuous improvement in the areas of safety culture, self-verification and training.

Safety performance

	2015	2014	2013
Recordable injury frequency	**0.26**	0.34	0.25
Day away from work case frequency	**0.092**	0.121	0.063
Severe vehicle accident rate	**0.09**	0.09	0.10
Loss of primary containment incidents number	**66**	82	101

We take measures to prevent leaks and spills at our refineries and other downstream facilities throughout the design, maintenance and operation of our equipment. We focus on managing the highest priority risks associated with our storage, handling and processing of hydrocarbons. We also seek to provide safe locations, emergency procedures and other mitigation measures in the event of a release, fire or explosion.

Process safety expert

Duane Wilson s three-year term as a board appointed process safety expert for our downstream activities came to a close during 2015. Mr Wilson provided an independent perspective on the progress that BP s fuels, lubricants and petrochemicals businesses have made toward becoming industry leaders in process safety performance. Before leaving, he shared his thoughts on possible areas for ongoing emphasis, such as risk management, progress measurement and leadership.

Other businesses and corporate safety

We report on the combined safety performance of our biofuels, wind and shipping businesses, as well as treasury and corporate activities, including centralized functions.

Safety performance

	2015	2014	2013
Recordable injury frequency	**0.29**	0.44	0.47
Day away from work case frequency	**0.077**	0.067	0.092
Severe vehicle accident rate	**0.35**	0.48	0.41
Loss of primary containment incidents number	**16**	17	17

Safety in our biofuels business

We have been working to deliver safe and reliable operations in our Brazilian biofuels business since our acquisition of Companhia Nacional de Açúcar e Álcool in 2011. We have done this by introducing a more systematic approach to personal, process and transportation safety. For example, we have segregated pedestrian access from several areas where we operate machinery in our agricultural operations, reducing the likelihood of injury to our workforce.

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 2015 52% of the 353 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 work with our supply chain on areas such as safety, operational performance, anti-bribery and corruption, money laundering and human rights, and aim to have suitable provisions in our contracts with contractors, suppliers and partners.

We seek to work with companies that share our commitment to ethical, safe and sustainable working practices. 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.

Contractors

We seek to set clear and consistent expectations of our contractors. Our standard model contracts include health, safety, security and environmental requirements, and most now include human rights 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 a site.

Our partners in joint arrangements

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 when engaging with operators and co-venturers.

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The Ocean Victory drilling rig in the Juniper field, Trinidad.

« Defined on page 256.

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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

We review our management of material issues such as climate change, water, how we work with communities and human rights. This includes examining emerging risks and actions taken to mitigate them. We identify areas for improvement and work to address these where appropriate.

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 and those that could affect an international protected area.

In the planning stages of these projects we complete a screening process to identify the most significant potential environmental and social impacts. We completed this process for five projects in 2015. 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 2015 totalled $8,017 million (2014 $4,024 million, 2013 $4,288 million), including charges related to the Gulf of Mexico oil spill. For a breakdown of environmental expenditure see page 233.

Climate change

Meeting the climate challenge requires efforts by all governments, companies and consumers. We believe governments must lead by providing a clear, stable and effective climate policy framework, including putting a price on carbon one that treats all carbon equally.

We expect that greenhouse gas (GHG) policy 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. There is a growing number of emission pricing schemes globally, including in Europe, California and China, additional monitoring regulations in the US, and more focus on reducing flaring and methane

emissions in many jurisdictions.

We are focusing on ways to reduce GHG emissions, including working to improve the energy efficiency of our operations and our products. Around half of our current upstream portfolio is natural gas, which produces about half as much carbon dioxide (CO_2) as coal per unit of power generated, and we operate renewable businesses in biofuels and onshore wind.

We currently 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 part of the economic evaluation of the investment.

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.

We are also working with our peers. For example, we are an active participant in the Oil and Gas Climate Initiative, a voluntary, CEO-led industry initiative that aims to catalyse meaningful action on climate change through best practice sharing and collaboration. We also joined with seven other oil and gas companies calling on the UN and governments to put a price on carbon.

See *bp.com/climatechange* for more information about our activities.

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.

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

Greenhouse gas emissions ($MteCO_2e$)

	2015	2014	2013
Operational control[a]			
Direct emissions	**51.4**[c]	54.1	
Indirect emissions	**7.0**	7.5[d]	
BP equity share[b]			
Direct emissions	**48.9**[c]	48.6	50.3
Indirect emissions	**6.9**	6.8[e]	6.7[f]

[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. In 2014 we changed our GHG reporting boundary from a BP equity-share basis to an operational control basis.
[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.
[c] The 2015 figure reflects our update of the global warming potential for methane from 21 to 25, in line with IPIECA s guidelines.
[d] The reported 2014 figure of 7.2Mte has been amended to 7.5Mte.
[e] The reported 2014 figure of 6.6Mte has been amended to 6.8Mte.
[f] The reported 2013 figure of 6.6Mte has been amended to 6.7Mte.

In 2015 we updated the global warming potential for methane from 21 to 25. Without this update, our reported direct emissions would have been lower, primarily due to divestments in Alaska.

The ratio of our total GHG emissions reported on an operational control basis to gross production was 0.24teCO_2e/te production in 2015 (2014 0.25teCO_2e/te). Gross production comprises upstream production, refining throughput and petrochemicals produced.

See *bp.com/greenhousegas* for more information about our GHG management and performance.

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Oil spill preparedness and response

We are working to continuously improve how we control, contain and clean up oil spills should they occur. Our requirements for oil spill preparedness and response planning, and crisis management incorporate what we have learned over many years of operation.

We updated our oil spill response plan requirements in 2012 to incorporate learnings from the Deepwater Horizon accident. Revised response plans include elements such as specialized modelling techniques to help predict the impact of potential spills, provision of stockpiles of dispersant, and the use of technologies like aerial and underwater robotic vehicles for environmental monitoring. This is a substantial piece of work and BP-operated businesses with the potential to spill oil are on track to complete updates by the end of 2016.

We continue to investigate and test whether emerging technologies can enhance our oil spill response capability. For example, in the Middle East, we have trialled the use of satellite imagery as a way to identify oil spills on land and track clean-up response time.

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 2015 we participated in response exercises with government regulators in regions such as Angola, the UK and US.

See page 43 for information on volume of oil spilled by our operations in 2015, including volume of oil unrecovered.

Water

BP recognizes the importance of managing fresh water use and water discharges in our operations and we review our water risks annually. We use industry-standard risk assessment tools, such as the IPIECA Global Water Tool and the World Resources Institute Aqueduct Global Water Atlas, to identify potential quantity, quality and regulatory risks across all our operated assets. We are assessing different technology approaches for optimizing water consumption and wastewater treatment performance. For example, we have evaluated different approaches for reducing fresh water use in our purified terephthalic acid operations, such as wastewater recycling and sea water cooling.

We monitor the increasing number of regulations pertaining to freshwater withdrawals and water discharge quality where we operate. This has led to investments in our wastewater treatment plants at our refineries in Europe and the US.

See *bp.com/water* for information about our approach to water.

Unconventional gas and hydraulic fracturing

Natural gas resources, including unconventional gas, have an increasingly important role in supplying lower-carbon fuel to meet the world s growing energy needs. BP is working to responsibly develop and produce natural gas from unconventional resources including shale gas, tight gas« and coalbed methane. We have unconventional gas operations in Oman and the US and we are evaluating unconventional gas opportunities in other countries.

Some stakeholders have raised concerns about the potential environmental and community impacts of hydraulic fracturing during unconventional gas development. 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 are working to minimize air pollutant and GHG emissions, such as methane, at our operating sites. For example, in the US we use a process called green completions at our gas operations. This process 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.

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Teams from BP Angola taking part in a shoreline oil spill response exercise the first international oil company event of its type in the country.

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Canada s oil sands

BP is involved in three oil sands lease areas in Canada. Sunrise, operated by Husky Energy, began producing oil in early 2015 and is currently producing approximately 20,000 barrels per day. Pike, operated by Devon Energy, is at the design stage. Terre de Grace, which is BP-operated, is currently under appraisal for development.

Our decision to invest in Canadian oil sands activities takes into consideration GHG emissions, impacts on the land, water use, local communities and commercial viability.

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 (the Guiding Principles) and incorporating them into the processes and policies that govern our business activities.

We are progressing towards alignment with the Guiding Principles using a risk-based approach. This includes working across functions and businesses in areas such as identifying and addressing human rights risks and impacts, community and workforce grievance mechanisms, and contracted workforce, working and living conditions and recruitment processes.

In 2015 our actions included:

- Development and delivery of guidance, tools and training courses to increase human rights awareness across the business.

- Inclusion of human rights clauses in an increasing number of our supplier contracts.

- Evaluation of our community grievance mechanisms against the Guiding Principles began at key sites to identify areas for improvement.

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

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

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. In Indonesia, for example, we have supported the foundation of local businesses, providing community members with technical and hands-on training. In the UK we support an apprenticeship programme in the North Sea run by one of our contractors. The programme provides training on the skills required for the safe and reliable operation of our offshore assets.

BP s community investments support development that meets local needs and are relevant to our business activities. We contributed $67 million in social investment in 2015.

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

Business ethics and transparency

Our code of conduct defines our commitment to high ethical standards.

Our values

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.

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 BP 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.

A total of 1,158 people contacted OpenTalk with concerns or enquiries in 2015 (2014 1,114, 2013 1,121). 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.

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Staff taking part in BP s code of conduct training in Brazil.

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We take steps to identify and correct areas of non-conformance and take disciplinary action where appropriate. In 2015 our businesses dismissed 132 employees for non-conformance with our code of conduct or unethical behaviour (2014 157, 2013 113). This excludes dismissals of staff employed at our retail service stations.

See *bp.com/codeofconduct* for more information.

In addition to our code of conduct, we have policies on a variety of related issues, including anti-bribery and corruption, political donations and human rights.

Anti-bribery and corruption

Bribery and corruption are significant risks in the oil and gas industry. We have a responsibility to our employees, 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 prohibits engaging in bribery and corruption in any form.

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

Lobbying and political donations

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 (PAC) to facilitate employee involvement and to assess whether contributions comply with the law and satisfy all necessary reporting requirements.

Tax and financial transparency

BP is committed to complying with tax laws in a responsible manner and to having open and constructive relationships with tax authorities. BP supports efforts to increase public trust in tax systems. We engage in initiatives to simplify and improve tax regimes to encourage investment and economic growth.

BP will start to disclose information on payments to governments on a country-by-country and project basis in 2016. The disclosure is required under the revenue transparency provisions contained in the EU Accounting Directive, which was recently brought into effect in UK law. We are awaiting the finalization and adoption of SEC rules under the US Dodd-Frank Act.

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 US.

See *bp.com/tax* for BP   s approach to tax.

Employees

BP s performance depends on having a highly skilled, motivated and talented workforce that reflects the diversity of the societies in which we operate.

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An employee at our service station in Twyford, UK. We are increasing the footprint of our retail presence in many European countries and actively recruiting in these markets.

BP employees

Number of employees at 31 December[a]	**2015**	2014	2013
Upstream	**21,700**	24,400	24,700
Downstream	**44,800**	48,000	48,000
Other businesses and corporate	**13,300**	12,100	11,200
Total	**79,800**	84,500	83,900
Service station staff	**15,600**	14,400	14,100
Agricultural, operational and seasonal workers in Brazil	**4,800**	5,300	4,300
Total excluding service station staff and workers in Brazil	**59,400**	64,800	65,500

[a] Reported to the nearest 100. For more information see Financial statements Note 34.

We aim to develop the capabilities of our workforce with a focus on the skills required to maintain safe and reliable operations. As we adapt to the current low oil price environment, we are reducing activity and simplifying the way we work. Some of this has resulted in job losses. Our employee headcount at the end of 2015 was 4,700 lower than the previous year.

Our total upstream workforce including employees and contractors is now 20% smaller than it was in 2013, with a reduction of around 4,000 expected in 2016. We are aiming for an upstream workforce of approximately 20,000 by the end of 2016. We expect to reduce our downstream workforce roles by more than 5,000 by the end of 2017 compared with 2014, excluding service station staff and the reallocation of around 2,000 global business services staff from Downstream to Other businesses and corporate in 2015. By the end of 2015, we had already achieved a reduction of more than 2,000.

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 2015 the committee discussed longer-term people priorities, reward, progress in our diversity and inclusion programme, employee engagement, and improvements to our training and development programmes.

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Attracting and retaining the right 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 those required for transporting and distributing hydrocarbons safely around the world. We have a bias towards building capability and promoting from within the organization and complement this with selective external recruitment. In 2015 90% of senior leadership roles were recruited from within BP.

We decided to maintain graduate recruitment in 2015, albeit at a reduced level, with a total of 298 graduates joining BP during the year (2014 670, 2013 814). We have worked to maintain our visibility in the graduate job market to help us attract the best recruits, and provide them with high quality early development opportunities. For the second consecutive year BP was the highest ranked energy-sector company in the UK in *The Times Top 100 Graduate Employers.*

In 2015 46% of our graduate intake were women and 41% were from outside the UK and US.

Building in-house capability

We provide a broad range of development opportunities for our people from on-the-job learning and mentoring through to online and classroom-based courses.

Through our internal academies, we provide leading technical, functional, compliance and leadership learning opportunities. We have six academies, focusing on our operating management system, petrotechnical skills, downstream, midstream, leadership, and functional skills, including finance and legal.

Diversity

As a global business, we aim for a workforce representative of the societies in which we operate. We set out our ambitions for diversity and our group people committee reviews performance on a quarterly basis.

Our aim is for women to represent at least 25% of group leaders our most senior managers by 2020 and we are actively seeking qualified female candidates for our board.

For more information on the composition of our board, see page 56.

Workforce by gender

Numbers as at 31 December	**Male**	Female	Female %
Board directors	**12**	3	20%
Group leaders	**350**	81	19%
Subsidiary directors	**1,099**	179	14%
All employees	**54,581**	25,234	32%

A total of 23% of our group leaders came from countries other than the UK and US at the end of 2015 (2014 22%, 2013 22%). 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 perform to their full potential, and for the business to excel, 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 ethnicity, national origin, religion, gender and gender identity, age, sexual orientation, marital status, disability, or any other characteristic protected by applicable laws. Where existing employees become disabled, our policy is to provide continued employment and training wherever possible.

Employee engagement

Managers hold regular team and one-to-one meetings with their staff, 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 identify areas where we can improve. We track how engaged employees are with our strategic priorities using our group priorities index, based on questions about their perception of BP as a business and how it is managed in terms of leadership and standards. This measure fell to 69% in 2015 (2014 72%, 2013 72%).

Our survey results show a strong increase in understanding and use of the code of conduct to guide behaviour and that employees remain clear about compliance with safety procedures, standards and requirements.

However, as expected in the current low oil price environment, the proportion of employees responding that they feel more confident about BP s future than they did the previous year has declined. We also saw a decline in scores related to development and career opportunities.

We understand that employees have concerns about the consequences of the lower oil price. We have established additional communications channels to help address these concerns and support employees through our restructuring processes. For example, our executive team has been holding additional face-to-face town hall meetings. In our upstream business we have introduced a dedicated inbox for queries and regular listening sessions between frontline staff and management, with a commitment to follow up on any issues raised.

Share ownership

We encourage employee share ownership and have a number of employee share plans in place. For example, under our ShareMatch plan, which operates in more than 50 countries, we match BP shares purchased by our employees. We also operate a group-wide discretionary share plan, which allows employee participation at different levels globally and is linked to the company s performance.

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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 53.

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 and policy 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 Group ethics and compliance committee for legal and regulatory compliance and ethics risks.

g Resource commitment meeting for investment decision risks.

Board and its committees

g BP board.

g Audit committee.

g Safety, ethics and environment assurance committee.

g Geopolitical committee.

g Gulf of Mexico committee.

Risk governance
For further information on risk management and internal control, see board and committee reports on page 64.

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 2016 are listed on page 52. 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.

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 53.

« Defined on page 256.

Risks for particular oversight by the board and its committees in 2016

The risks for particular oversight by the board and its committees in 2016 have been reviewed and updated. These risks remain the same as in 2015 other than the Gulf of Mexico oil spill and major project« delivery risks, which are no longer considered to require this additional oversight in 2016. Financial resilience has been added to the high priority risks for particular oversight in 2016. This update reflects the proposed settlements between BP, the United States government and the five Gulf Coast states with respect to federal and state claims arising from the oil spill, as well as current market conditions. Both the Gulf of Mexico oil spill and major project delivery risks will continue to be monitored as appropriate by the board and its committees in the normal course of risk oversight and management.

Strategic and commercial risks

Financial resilience

External market conditions can impact our financial performance. Supply and demand and the prices achieved for our products can be affected by a wide range of factors including political developments, technological change, global economic conditions and the influence of OPEC.

We actively manage this risk through BP s diversified portfolio, our financial framework, liquidity stress testing, regular reviews of market conditions and our planning and investment processes.

For more information on our financial framework see page 18, Our strategy on page 13, Our markets in 2015 on page 24 and Liquidity and capital resources on page 219.

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 and implement risk mitigation plans where appropriate. We established a new board committee focusing on geopolitical risk in 2015.

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 a range of measures, which include cybersecurity standards, ongoing monitoring of threats and testing of cyber response procedures and equipment. We collaborate closely with governments, law enforcement agencies and industry peers to understand and respond to new and emerging cyber threats. Campaigns and presentations on topics such as email phishing and protecting our information and equipment have helped to raise employee 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 43.

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 our businesses through 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 threats globally and, in particular, the situation in the Middle East and North Africa.

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 2012 criminal settlement with the US Department of Justice and the 2014 settlement with the US Environmental Protection Agency, an ethics monitor is reviewing and providing recommendations concerning BP s ethics and compliance programme.

Find out more about our code of conduct and our business ethics on page 48, and the ethics monitor on page 42.

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 33, Downstream supply and trading on page 36 and Financial statements Note 28.

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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.

Strategic and commercial risks

Prices and markets our financial performance is subject to fluctuating prices of oil, gas, refined products, technological change, 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 demand and prices for our products. Decreases in oil, gas or product prices could have an adverse effect on revenue, margins, profitability and cash flows. If significant or for a prolonged period, we may have to write down assets and re-assess the viability of certain projects, which may impact future 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.

Events in or relating to Russia, including further trade restrictions and other sanctions, could adversely impact our income and investment in Russia. Our ability to pursue business objectives and to recognize production and reserves relating to Russia could also 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 219 and Financial statements Note 28.

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.

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 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.

« Defined on page 256.

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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 43.

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 characteristics 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 announced in November 2012 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.

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, and could result in litigation, regulatory action and penalties.

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 oversight 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 28.

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.

Gulf of Mexico oil spill

There continues to be uncertainty regarding the extent and timing of the remaining costs and liabilities relating to the Gulf of Mexico oil spill not covered by the proposed Consent Decree and the Settlement Agreement.

The proposed Consent Decree between the United States, the five Gulf Coast states and BP and the Settlement Agreement between BP and the Gulf Coast states will, subject to these becoming effective, settle all federal and state claims arising from the 2010 Gulf of Mexico oil spill. The proposed Consent Decree and the Settlement Agreement are conditional upon each other and neither will become effective until there is final approval of the Consent Decree. There continues to be uncertainty regarding the extent and timing of the remaining costs and liabilities relating to the Gulf of Mexico oil spill not covered by the proposed Consent Decree and the Settlement Agreement. For items not covered by the proposed Consent Decree and the Settlement Agreement and for further information, see Financial statements Note 2 and Legal proceedings (page 237).

The Strategic report was approved by the board and signed on its behalf by David J Jackson, company secretary on 4 March 2016.

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Board of directors
As at 4 March 2016

See BP s board governance principles relating to director independence on page 244.

Board biographies

See *bp.com/governance*

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Carl-Henric Svanberg

Chairman

Tenure

Appointed 1 September 2009

Outside interests

Chairman of AB Volvo

Age 63 **Nationality** Swedish

Career

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

He spent his early career at Asea Brown Boveri and the Securitas Group, before moving to the Assa Abloy Group as president and chief executive officer.

From 2003 until 31 December 2009, when he left to join BP, he was president and chief executive officer of Ericsson, also serving as the chairman

Career

Bob Dudley became group chief executive on 1 October 2010.

Bob joined Amoco Corporation in 1979, working in a variety of engineering and commercial posts. Between 1994 and 1997, he worked on corporate development in Russia. In 1997 he became general manager for strategy for Amoco and in 1999, following the merger between BP and Amoco, was appointed to a similar role in BP.

Between 1999 and 2000, he was executive assistant to the group chief executive, subsequently becoming group vice president for BP s renewables and alternative energy activities. In 2002 he became group vice president responsible for BP s upstream businesses in Russia, the Caspian region, Angola, Algeria and Egypt.

From 2003 to 2008 he was president and chief executive officer of TNK-BP. On his return to BP in 2009 he was

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 US, he became Downstream s chief financial officer and commercial director from 2002 to 2005. From 2005 to 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.

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.

Brian will also take on accountability for integrated supply and trading and shipping during 2016.

SEEAC with that of the audit committee, to provide a cohesive and robust overview of business risks.

His experience of business in the US and its regulatory environment has greatly assisted the work of the Gulf of Mexico committee and is an asset to the geopolitical committee.

Alan Boeckmann

Independent non-executive director

Tenure

Appointed 24 July 2014

Outside interests

Non-executive director of Sempra Energy

Non-executive director of Archer Daniels Midland

Age 67 **Nationality** American

of Sony Ericsson Mobile Communications AB. He was a non-executive director of Ericsson between 2009 and 2012. He was appointed chairman and a member of the board of AB Volvo in 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 is a highly experienced leader of global corporations. He has served as both chief executive officer and chairman to high profile businesses, giving him a deep understanding of international strategic and commercial issues. His experience allows him to co-ordinate the diverse range of knowledge and skills provided by the board.

Bob Dudley

Group chief executive

appointed to the BP board and oversaw the group s activities in the Americas and Asia. Between 23 June and 30 September 2010 he served as the president and chief executive officer of BP s Gulf Coast Restoration Organization in the US. He was appointed a director of Rosneft in 2013 following BP s acquisition of a stake in Rosneft.

Relevant skills and experience

Bob Dudley has spent his whole career in the oil and gas industry. He has held senior management roles in Amoco and BP and as the chief executive officer of TNK-BP from 2003 to 2008.

Over the five years that he has been group chief executive, Bob has transformed BP into a safer, stronger and simpler business. By focusing the group s approach on value not volume and operating through a set of consistent values, Bob has guided BP s recovery to a position of greater resilience, to enable it to continue delivering results in an uncertain economic environment.

Dr Brian Gilvary

Relevant skills and experience

Dr Brian Gilvary has spent his entire career with BP. He has a strong knowledge of finance and trading, a deep understanding of BP s assets and businesses and has very broad experience of the business as a whole.

Brian has been instrumental in transforming BP s capital structure and operational costs during its recovery and as it adjusts to a low oil price environment, while ensuring the group is capable of meeting new opportunities going forward.

Paul Anderson

Independent non-executive director

Tenure

Appointed 1 February 2010

Outside interests

No external appointments

Career

Alan Boeckmann retired as non-executive chairman of Fluor Corporation in February of 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. As chairman and CEO, 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 and the National Petroleum Council. He

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

Member of the World Economic Forum (WEF) International Business Council

Chair of the WEF Oil and Gas Climate Initiative

Member of the Russian Geographical Society Board of Trustees

Fellow of the Royal Academy of Engineering

Age 60 **Nationality** American

Chief financial officer

Tenure

Appointed to the board 1 January 2012

Outside interests

Visiting professor at Manchester University

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

Nominated for appointment by the AGM as a non-executive director of L Air Liquide S.A. from May 2016

Member of the 100 Group Committee

GB Age Group triathlete

Age 54 **Nationality** British

Age 70 **Nationality** American

Career

Paul Anderson was formerly chief executive at BHP Billiton and Duke Energy, where he also served as chairman of the board. Having previously been chief executive officer and managing director of BHP Limited and then BHP Billiton Limited and BHP Billiton Plc, he rejoined these latter two boards in 2006 as a non-executive director, retiring in January 2010. Previously he 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.

Relevant skills and experience

Paul Anderson has spent his career in the energy industry working with global organizations, and brings the skills of an experienced chairman and chief executive officer to the board. As chairman of the SEEAC since 2012, he has maintained the board s focus on safety and broader non-financial issues. This year he has worked with Brendan

was also a board member and trustee of the Eisenhower Medical Center in Rancho Mirage, California 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

Alan Boeckmann has been a chairman and chief executive officer in the worldwide engineering and construction industry and in the energy sector. He brings deep experience to the board and in his roles on the SEEAC and Gulf of Mexico committee, not only from his profession as an engineer but also of international project management and procurement.

Alan joined the remuneration committee in 2015.

Nelson to integrate the
oversight of the

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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

Age 71 **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.

Antony Burgmans

Independent non-executive director

Tenure

Appointed 5 February 2004

Outside interests

Member of the supervisory board of SHV Holdings NV

Chairman of the supervisory board of TNT Express

Chairman of Akzo Nobel NV

Age 69 **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.

American plc, the global mining group, operating in 45 countries with 150,000 employees, and was chairman of De Beers s.a. and Anglo Platinum Limited. She stepped down from these roles in April 2013.

Relevant skills and experience

Cynthia Carroll has led multiple large complex global businesses in the 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 is an experienced former chief executive who has spent all of her career in the extractive industries, having trained as a petroleum geologist. Her leadership experience related to enhancing safety in the mining industry brings a strong contribution to the work of the SEEAC, as does her understanding of business strategy in an industry with a long capital return cycle. Her international experience with

Professor Dame Ann Dowling

Independent non-executive director

Tenure

Appointed 3 February 2012

Outside interests

President of the Royal Academy of Engineering

Deputy vice-chancellor and Professor of Mechanical Engineering at the University of Cambridge

Member of the Prime Minister s Council for Science and Technology

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

Age 63 **Nationality** British

Career

He 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 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 implications of climate change for naval forces.

Relevant skills and experience

Frank Bowman brings exceptional experience in safety issues arising from his

In 1991, he was appointed to the board of Unilever, becoming business group president, ice cream and frozen foods Europe in 1994, and chairman of Unilever s Europe committee, co-ordinating its European activities. In 1998, he became vice chairman of Unilever NV and in 1999, chairman of Unilever NV and vice chairman of Unilever PLC. In 2005 he became non-executive chairman of Unilever NV and Unilever PLC until his retirement in 2007. During his career he has lived and worked in London, Hamburg, Jakarta, Stockholm and Rotterdam.

Relevant skills and experience

Antony Burgmans is an experienced chairman and chief executive who 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 has served on the board for 12 years and has made a major contribution to the SEEA and remuneration

governments is an asset to the geopolitical committee.

Ian Davis

Independent non-executive director

Tenure

Appointed 2 April 2010

Outside interests

Chairman of Rolls-Royce Holdings plc

Non-executive director of Majid Al Futtaim Holding LLC

Non-executive director of Johnson & Johnson Inc

Non-executive director of Teach for All

Age 64 **Nationality** British

Career

Ian Davis is senior partner emeritus of McKinsey & Company. He was a partner at McKinsey for 31 years until 2010 and served as chairman and

Dame Ann Dowling is a deputy vice-chancellor at the University of Cambridge, where she was appointed a professor of mechanical engineering in the department of engineering in 1993. She was head of the department of engineering at the University of Cambridge from 2009 to 2014. Her research is in fluid mechanics, acoustics and combustion, and she has held visiting posts at MIT and at Caltech. She was appointed director of the University Gas Turbine Partnership with Rolls-Royce in 2001, and chairman in 2009. Between 2003 and 2008 she chaired the Rolls-Royce propulsion and power systems advisory board and now chairs BP s technical advisory committee.

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 the French Academy of Sciences. She has honorary degrees from nine universities, including the University of Oxford, Imperial College London and the KTH Royal Institute of Technology, Stockholm.

time with the US Navy and the Nuclear Energy Institute, coupled with direct knowledge of BP s safety goals from his work on the BP Independent Safety Review Panel. He also has a broad perspective of systems and of people from the many other roles throughout his career.

He has built on this experience with the Gulf of Mexico and SEEA committees since 2010 and his background and experience of US and global political and regulatory systems are valuable assets to the geopolitical committee.

committees and latterly through chairing the geopolitical committee.

Cynthia Carroll

Independent non-executive director

Tenure

Appointed 6 June 2007

Outside interests

Chair of Vedanta Resources Holding Ltd

Non-executive director of Hitachi Ltd

Age 59 **Nationality** American

Career

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,

managing director between 2003 and 2009.

Ian has a MA in Politics, Philosophy and Economics from Balliol College, University of Oxford.

Relevant skills and experience

Ian Davis brings the skills of a managing director with significant financial and strategic experience to the board. He has worked with and advised global organizations and companies in a wide variety of sectors including oil and gas and the public sector, enabling him to draw on knowledge of diverse issues and outcomes to assist the board. His role in the Cabinet Office, from which he stepped down in March 2016, 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.

She was elected President of the Royal Academy of Engineering in September 2014. In December 2015 she was appointed to the Order of Merit, which is in the sole gift of the Queen and limited to just 24 members.

Relevant skills and experience

Dame Ann Dowling is an internationally respected leader in engineering research and the practical application of new technology in industry. The department of engineering at Cambridge University that she led is one of the leading centres for engineering research worldwide, and her contribution has been widely recognized by universities around the world. She chairs BP s technical advisory committee and makes a significant contribution to the work of the SEEAC.

Dame Ann became chair of the remuneration committee in 2015 and has spent time with key shareholders to listen and reflect their views in the work of the committee.

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 chief executive of Anglo

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Brendan Nelson

Independent non-executive director

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 Review Panel

Age 66 **Nationality** British

Career

Brendan Nelson is a chartered accountant. He was made a partner of KPMG in 1984. He served as a member of the UK board of KPMG from 2000 to 2006, subsequently being appointed vice chairman until his retirement in 2010. At KPMG International he held a number of senior positions including global chairman, banking and global chairman, financial services.

March 2011. He was formerly a director of a number of listed South African companies, including Johnnic Holdings (formerly a subsidiary of the Anglo American group of companies), Nedbank Group, Bidvest Group and Alexander Forbes.

Relevant skills and experience

Phuthuma Nhleko has had a wide-ranging career in infrastructure, banking and telephony as well as the extractive industries. This broad experience leading multinational companies, particularly in emerging markets, enables him to contribute strongly to the board and geopolitical committee on strategic matters. His commercial experience also gives him insight into financial issues relevant to the audit committee.

Paula Rosput Reynolds

Independent non-executive director

Tenure

Paula has led several groups through restructuring and mergers so can contribute knowledge and experience to the board when considering simplification and value creation.

Sir John Sawers

Independent non-executive director

Tenure

Appointed 14 May 2015

Outside interests

Chairman and partner of Macro Advisory Partners LLP

Visiting professor at King s College London

Governor, Ditchley Foundation

Age 60 **Nationality** British

Career

Andrew Shilston

Senior independent non-executive director

Tenure

Appointed 1 January 2012

Outside interests

Chairman of Morgan Advanced Materials plc

Non-executive director of Circle Holdings plc

Age 60 **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

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 Accountants of Scotland.

Relevant skills and experience

Brendan Nelson s career in audit and finance makes him ideally suited to chair the audit committee and to act as its financial expert. He held a range of senior leadership roles at KPMG giving him broad management and business experience. His specialism in the financial services industry allows him to contribute insight into the challenges faced by global businesses by regulatory frameworks.

Brendan brings related input from his role as the chair of the audit committee of a major bank and as a member of the Financial Reporting Review Panel.

Phuthuma Nhleko

Independent non-executive director

Tenure

Appointed 14 May 2015

Outside interests

Non-executive director of BAE Systems Ltd

Non-executive director of TransCanada Corporation

Non-executive director of Siluria Technologies

Age 59 **Nationality** American

Career

Paula Rosput Reynolds is the former chairman, president and chief executive officer of Safeco Corporation, a Fortune 500 property and casualty insurance company that was acquired by Liberty Mutual Insurance Group in 2008. She also served as vice-chair and chief restructuring officer for American International Group (AIG) for a period after the US government became the financial sponsor from 2008 to 2009.

Previously Paula was an executive in the energy industry. She was chairman, president and

John Sawers spent 36 years in public service in the UK, working on foreign policy, international security and intelligence.

John was Chief of the Secret

Intelligence Service, MI6, from 2009 to 2014, a period of international upheaval and growing security threats as well as closer public scrutiny of the intelligence agencies. Prior to that, the bulk of his career was in diplomacy, representing the British government around the world and leading negotiations at the UN, in the European Union and in the G8. He was the UK ambassador to the United Nations (2007-09), political director and main board member of the Foreign Office (2003-07), special representative in Iraq (2003), ambassador to Egypt (2001-03) and foreign policy advisor to the Prime Minister (1999-2001). Earlier in his career, he was posted to Washington, South Africa, Syria and Yemen.

John is now chairman of Macro Advisory Partners, a firm which advises clients on the intersection of policy, politics and markets.

the sale of Enterprise Oil to Shell in 2002, in 2003 he became finance director of Rolls-Royce plc until his retirement in December 2011.

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 is a highly knowledgeable director with wide experience from roles in finance, from several positions as a chief financial officer, and the oil and gas industry in general. His deep understanding of commercial issues has assisted the board in its work in overseeing the group s strategy and in particular the evaluation of capital projects, while his financial skills are an asset to both the audit and remuneration committees.

As senior independent director he has overseen the evaluation of the chairman and led the external evaluation of the board in 2015.

Appointed 1 February 2011

Outside interests

Non-executive director and chairman of MTN Group Ltd

Chairman of the Pembani Group

Age 55 **Nationality** South African

Career

Phuthuma Nhleko began his career as a civil engineer in the US and as a project manager for infrastructure developments in southern Africa. Following this he became a senior executive of the Standard Corporate and Merchant Bank in South Africa. He later held a succession of directorships before joining MTN Group, a pan-African and Middle Eastern telephony group represented in 21 countries, as group president and chief executive officer in 2002. During his tenure at the MTN Group he led a number of substantial mergers and acquisitions transactions.

He stepped down as group chief executive of MTN Group at the end of

chief executive officer of AGL Resources Inc., an operator of natural gas infrastructure in the US. Prior to this, she led a subsidiary of Duke Energy Corporation that was a merchant operator of electricity generation. She commenced her energy career at PG&E Corp.

She currently chairs the board of the Fred Hutchinson Cancer Research Center in Seattle, Washington. In 2014 Paula was awarded the National Association of Corporate Directors (US) Lifetime Achievement Award.

Relevant skills and experience

Paula Rosput Reynolds has had a long career leading global companies in the energy and financial sectors. Her experience with international and US companies gives her insight into strategic and regulatory issues, and her financial background is an asset to the audit committee.

Relevant skills and experience

Sir John Sawers deep experience of international political and commercial matters is an asset to the board in navigating the complex issues faced by a modern global company. His management of reform at MI6 also complements BP s focus on value and simplification.

As a former UK government representative, Sir John brings knowledge and skills related to analysing and negotiating on a worldwide basis, which are invaluable to the geopolitical and SEEA committees.

David Jackson

Company secretary

Tenure

Appointed 2003

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

The ages of the board are correct as at 4 March 2016.

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Executive team

As at 4 March 2016

Rupert Bondy

Current position

Group general counsel

Executive team tenure

Appointed 1 May 2008

Outside interests

Non-executive director, Indivior PLC

Age 54 **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

Prior to this, Bob was chief executive of BP Angola and also held several management positions in 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.

During 2016 Bob will also take on accountability for remediation management.

Andy Hopwood

Current position

Chief operating officer, strategy and regions, Upstream

Executive team tenure

Appointed 1 November 2010

Outside interests

No external appointments

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 US Department of Energy s US Clean Energy Education & Empowerment program

Age 56 **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

Appointed 1 October 2014

Outside interests

Current position

Executive vice president, safety and operational risk

Executive team tenure

Appointed 1 October 2010

Outside interests

No external appointments

Age 52 **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 30 years experience in the oil and

Age 58 **Nationality** British

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

Independent non-executive director of GKN plc

Member of the Turkish-British Chamber of Commerce & Industry Board of Directors

Age 56 **Nationality** British and Turkish

gas industry, having joined Amoco Production Company in 1985. Between 2010 and 2013, Bob was executive vice president of the production division and was accountable for safe and compliant exploration and production operations and stewardship of resources across all regions.

sustainability committee.

Katrina will step down from her executive vice president role in May 2016 and will retire from BP in July 2016.

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Bernard Looney

Current position

Chief operating officer, production

Executive team tenure

Appointed 1 November 2010

Outside interests

Fellow of the Royal Academy of Engineering

Member of the Stanford University Graduate School of Business Advisory Council

Fellow of the Energy Institute

Age 45 **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

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 57 **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.

Dev Sanyal

Current position

Executive vice president, strategy and regions

Executive team tenure

Appointed 1 January 2012

Outside interests

Independent non-executive director of Man Group plc

Member of the Accenture Global Energy Board

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

Vice Chairman of the Centre for China in the World Economy, Tsinghua University

Age 50 **Nationality** British and Indian

Career

Helmut Schuster

Current position

Executive vice president, group human resources

Executive team tenure

Appointed 1 March 2011

Outside interests

Non-executive director of Ivoclar Vivadent AG, Germany

Age 55 **Nationality** Austrian

Career

Helmut Schuster became group human resources (HR) director on 1 March 2011. He completed his post graduate diploma in international relations and his PhD in economics at the University of Vienna and then began his career working for Henkel in a marketing capacity. Since 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 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. He became executive vice president, developments, in October 2010 and took up his current role in February 2013.

During 2016 Bernard will take on the role of chief executive, upstream, in addition to maintaining his current portfolio.

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.

During 2016 Lamar will take on the role of deputy group chief executive. In addition to assuming some of the group chief executive s duties he will be accountable for group

Dev Sanyal is responsible for the Europe and Asia regions and functionally for group strategy and long-term planning, risk management, government and political affairs, policy and group integration.

Dev joined BP in 1989 and has held a variety of international roles in London, Athens, Istanbul, Vienna and Dubai. He was general manager, former Soviet Union and eastern Europe, prior to being appointed chief executive, BP Eastern Mediterranean Fuels in 1999.

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.

During 2016 Dev will take on the role of chief executive, alternative energy and executive vice president, regions.

joining BP in 1989 Helmut has held a number of leadership roles. He has worked in BP in the US, UK and continental Europe and within most parts of refining, marketing, trading, and gas and power.

Before taking on his current role his portfolio of responsibilities as a vice president, HR 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 and included businesses such as petrochemicals, fuels value chains, lubricants and functional experts across the group. He is also a non-executive director of BP Europa SE.

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 page 57) and the senior management listed left.

strategy and long-term planning, safety and operational risk, group technology and will also focus on various corporate governance activities including ethics and compliance.

The ages of the executive team are correct as at 4 March 2016.

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Introduction from the chairman

The membership and work of the board have continued to evolve during 2015. This has been driven by several factors, not least the challenging oil price environment which now dominates our industry. In the years following the Deepwater Horizon accident, the workload of the board, as I have previously reported, increased substantially in response to the issues with which the company was faced. While the number of our meetings has decreased, we still face evolving challenges and I am grateful to Bob, his executive colleagues and my fellow directors for the work that they have done. The commitment required of all of us certainly has not reduced with the number of meetings.

This means that we have to keep refreshed the way in which we work, the matters that we discuss and the decisions that we take. It remains our goal to keep our board time clear for strategic thinking while asking the committees to undertake much of the core tasks of monitoring and oversight. We need to ensure that we have the right skills round the board table to carry out these tasks.

External interest in what boards do increases year on year and it is for this reason that we set out, in the following detail, a description of our activities. Our agendas are prepared in such a way that we have the time to discuss the key issues of the moment without affecting the proper oversight of those matters with which we have to deal. As will be seen from the reports of the committees, directors have visited a number of BP s facilities during the year. This is a key part not only of building our understanding of the business but also testing the mood and the morale of our people in these difficult times.

As we look to the future, it is vital that the work of the board evolves with the business. We cannot be working to one rhythm while the business works to another. It is all too easy for a board to work to a historic schedule created to address past challenges. For this reason I am pleased that this year we have carried out a fully externally facilitated evaluation. We are reflecting on the conclusions which are set out elsewhere; it is important that we keep on learning. However, behind all of this an effective board has to keep asking itself two key questions: are we talking about the right things and are we adding value?

It is some time since we reviewed our governance policies. We will be doing this in 2016. The results of our evaluation will be part of this process. Prompted by changes to the Governance Code, we have further focused on risk and our systems of internal control. This has been a valuable process for the board. After what seems almost annual changes to the Code, I welcome the FRC s decision that this will not be reviewed again until 2019, enabling the UK governance landscape to settle and establish. I am however looking forward to BP being able to contribute to the FRC s work on succession and culture, which both remain key issues for any board.

Carl-Henric Svanberg

Chairman

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The board in 2015

Board membership

On 1 January 2016 the board had 15 directors the chairman, two executive directors and 12 independent non-executive directors (NEDs).

NEDs are expected to be independent in character and judgement and free from any business or other relationship that could materially interfere with exercising that judgement. It is the board s view that all NEDs, with the exception of the chairman, are independent. See page 244 for a description of BP s board governance principles relating to director independence.

The board benefits significantly from the diverse balance of background, gender, skills and experience represented by the NEDs. There are three female directors on the board and three directors from non-UK/US backgrounds.

Director	Key skills and experience
Paul Anderson	Oil and gas industry experience; leading a global business
Alan Boeckmann	Engineering, construction and procurement; leading a global business
Admiral Frank Bowman	Safety, technology, engineering and risk management
Antony Burgmans	Food and consumer goods; leading a global business
Cynthia Carroll	Oil, gas and extractive industry experience; leading a global business
Professor Dame Ann Dowling	Engineering, technology and education
Ian Davis	Strategy, advisory and consulting
Brendan Nelson	Audit, financial services and trading

Phuthuma Nhleko	Civil engineering, telecoms and banking
Paula Rosput Reynolds	Energy industry; leading a global business
Sir John Sawers	International affairs
Andrew Shilston	Oil and gas industry experience; finance
Carl-Henric Svanberg	Manufacturing and telecoms; leading a global business

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

Paula Rosput Reynolds joined the board in May 2015 as a non-executive director. She is a member of the audit committee and the chairman s committee.

Sir John Sawers also joined the board in May 2015 as a non-executive director. He is a member of the safety, ethics and environment assurance committee, the geopolitical committee and the chairman s committee.

George David, a non-executive director, retired from the board at the annual general meeting on 16 April 2015.

Professor Dame Ann Dowling became the chair of the remuneration committee when Antony Burgmans stood down from the role in July 2015. Andrew Shilston and Alan Boeckmann joined the remuneration committee after the 2015 annual general meeting.

Antony Burgmans became chair of the newly formed geopolitical committee in September 2015. Antony Burgmans will step down from the board at the 2016 AGM after 12 years of service as a non-executive director. Sir John Sawers will then take the chair of the geopolitical committee.

Phuthuma Nhleko will step down from the board at the 2016 AGM after five years of service due to external business commitments.

Board meetings

There were 13 board meetings in 2015, of which two were carried out by teleconference. All directors attended every meeting for which they were eligible, with the following exceptions:

Phuthuma Nhleko did not attend the board meeting scheduled at short notice on 15 June due to prior commitments.
Antony Burgmans, Cynthia Carroll, Brendan Nelson, Paula Rosput Reynolds and Sir John Sawers did not attend the board meeting scheduled at short notice on 23 June due to prior commitments.
Phuthuma Nhleko did not attend the board meeting on 3 December due to urgent business commitments.

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 and his evaluation is led by the senior independent director.

The evaluation operates on a three-year cycle, with one externally led evaluation followed by two subsequent years of internal evaluations carried out using a questionnaire prepared by an external facilitator.

Activity following prior year evaluation

An evaluation was carried out at the end of 2014 by means of a questionnaire, facilitated by an external consultant (Lintstock). The evaluation concluded that reports from the business and on major projects were robust and informative. In a changing economic and geopolitical climate, the board was keen to ensure that it managed its time to allow appropriate levels of discussion by balancing the board s monitoring activities with discussion on strategic matters: this has been achieved by agenda planning during the year. The evaluation highlighted the future role of technology in delivering BP s strategy: briefings on this topic were planned into the board s agenda, including a technology presentation with respect to climate change.

2015 evaluation

For 2015 an externally facilitated evaluation was held in addition to, and to an extent based on, the established annual questionnaire process. Following a selection process led by the senior independent director, Bvalco was engaged as the external evaluator. The results of the annual questionnaire process were shared with the external evaluator who conducted a series of interviews with each director, members of the executive team and those who attended or supported the board. Interviews were focused on evaluating the effectiveness and performance of the board, and separately that of the chairman. In addition to these interviews, the evaluators reviewed the board agendas and materials for the past year and observed a board meeting.

The evaluation tested key areas of the board s work including its participation in the formation of strategy, succession and composition, and its oversight of business performance, risk and governance processes. The effectiveness of the committees in alleviating the oversight task of the board was also tested and focus was given to whether the board added value.

Results of the board evaluation and feedback from these interviews were collectively discussed by the board at its meeting in January 2016, with the results of the chairman s evaluation discussed by the chairman s committee.

The evaluation concluded:

Recognizing the current state of the market and important developments for the company during the year, there was a continued desire to ensure an effective strategy process that focused on the long term and which acknowledged the important role of the board in this process.
Good progress had been made in succession for the board; going forward this would continue to be built on.
The board was seen to have a collaborative and inclusive environment. To build on this further, the board agreed to try and put more of their monitoring tasks into the committees to allow more time for broader discussions at the board.

Committee work was seen as being of a high quality. Given the breadth of topics covered by the committees, further steps should be taken to ensure that where appropriate all directors could access information and attend external visits for those committees of which they were not members.

It was noted that the board governance principles would be reviewed and amended to capture these conclusions, where appropriate, and to reflect the current roles and practices within the board.

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Board activity

The board s activities are structured to enable the directors to fulfil their role, in particular with respect to strategy, risk, performance and monitoring.

Board focus in 2015

Strategy

The board discussed strategy or strategic elements at every full meeting. The board also reviewed the *BP Energy Outlook,* updated in February 2015, which looks at long-term energy trends and develops projections for world energy markets over the next two decades.

In January the executive team presented the 2015 annual plan to describe how the strategy should be implemented. The board met for two days in Houston in September to review the strategy in depth.

Risk

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.

The board considered the allocation of group risks between the monitoring committees (the audit, SEEA, and Gulf of Mexico committees, and from September, the geopolitical committee) and the board itself, and confirmed the schedule for oversight of these risks. The group risks reviewed by the board during 2015 included risks associated with the delivery of major projects«, particularly in the Upstream, and geopolitical risk associated with BP s operations around the world. For 2016 the group risks allocated to the board for review include financial resilience (which examines how the group is able to respond to a volatile oil and gas price environment) and cybersecurity (with the audit committee and SEEAC reviewing elements of cybersecurity risk in their work over the year). The group risks allocated to the committees for review over the year are outlined in the reports of the committees on pages 68-72.

Further information on BP s system of risk management is outlined in Our management of risk on page 51.

Performance

The board reviews financial and operational performance at each meeting. It receives regular updates on the group s performance for the year across a range of metrics as well as the latest view on expected full-year delivery against external scorecard measures. Updates are also given on various components of value delivery for BP s business.

The board reviews the quarterly and full-year results, including reviewing shareholder distribution policy. Both the 2014 and 2015 annual reports were assessed in terms of the directors obligations and appropriate regulatory requirements.

Monitoring

All meetings include a report from the chair of each committee that has met since the last meeting. These are supplemented with feedback on board and committee site visits, including a deep dive on exploration at the upstream learning centre in Sunbury in May.

The board monitors employee opinion via an annual pulse survey which includes measurement of how the BP values are incorporated into daily culture around our global operations.

The board received an update in December on BP s reputation in the US and UK compared with competitors, based on the results of our 2015 reputation research across a number of consistent reputational attributes measured over time.

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Training and induction

To help develop an understanding of BP s business, the board continues to build its knowledge through briefings and field visits. In 2015 the board received training on ethics and compliance, and the introduction of the new longer-term viability statement. The board met local management and external stakeholders at its board meetings in Sunbury and Houston.

NEDs are expected to attend at least one field visit per year. In 2015 the audit committee visited the cybersecurity centre in Houston and members of the SEEAC visited BP s operations in Trinidad, Oman and Rotterdam. After each visit, the board or appropriate committee was briefed on the impressions gained by the directors during the visit.

The two new NEDs, Paula Rosput Reynolds and Sir John Sawers followed a structured induction process. This included one-to-one meetings with management and the external auditors and also covered the board committees that they joined.

Director induction programme	
Board and governance	
g	BP s board governance model, directors duties, interests and potential conflicts.
Business introduction	
g	BP s business.
g	Upstream (exploration, development, production, overview of our operations).
g	Downstream (refining, marketing and lubricants).
g	Strategy and planning.
g	BP s performance relative to its competitors.
Functional input	
g	Finance and tax.

- Controls, external auditors and internal audit.
- Human resources.
- Ethics and compliance.
- Safety and operational risk (S&OR), BP s operating management system (OMS) and environmental performance.
- Research and technology.
- Trading.

After completing the induction, the directors are asked for feedback on the process to help further improve it going forward.

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 2015

January	g	*BP Energy Outlook* presentation
February	g	Fourth quarter results
	g	Investor roadshows with the group chief executive and chief financial officer
March	g	Engagement on remuneration and governance issues
	g	Chairman and board committee chairs meeting
	g	UKSA private shareholders meeting
	g	SRI roadshow following the launch of *BP Sustainability Report 2014*
April	g	Annual general meeting
	g	First quarter results
	g	*BP s response to lower oil prices* launch
June	g	*BP Statistical Review of World Energy* launch
July	g	Second quarter results
	g	Investor roadshows with the group chief executive and chief financial officer
	g	Institutional Investors Group on Climate Change meeting
August	g	Engagement with UKSA private shareholder panel on BP s 2014 financial reports
September	g	Oil and gas sector conferences
October	g	Third-quarter results and medium-term outlook

November	g	SRI annual meeting
	g	*BP Technology Outlook* launch
	g	Meetings with investors on remuneration (into December)
December	g	*Medium-Term Outlook* launched on *bp.com*

« Defined on page 256.

Institutional investors

Senior management regularly meets with institutional investors through roadshows, group and one-to-one meetings and events for socially responsible investors (SRIs).

During the year the chairman and remuneration committee chair held individual investor meetings to discuss strategy, the board s view on BP s performance, governance and remuneration. In March the chairman and all board committee chairs held an annual investor event. This meeting enabled BP s largest shareholders to hear about the work of the board and its committees and for NEDs to engage with investors.

In November 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, the group s approach to operational risk, context for the sector and BP in terms of oil price and energy supply-demand, operating and energy performance in the Upstream, and BP s response to the shareholder resolution.

See *bp.com/investors* for 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 2015. 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 and performance. Later in the year, the UKSA met with the company to give feedback on BP s 2014 financial reports.

AGM

Voting levels decreased slightly in 2015 to 62.28% (of issued share capital, including votes cast as withheld), compared to 63.13% in 2014 and 64.24% in 2013. Each year the board receives a report after the AGM giving a breakdown of the votes and investor feedback on their voting decisions to inform the board on any issues arising.

UK Corporate Governance Code compliance

BP complied throughout 2015 with the provisions of the UK Corporate Governance Code (the 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. Our letters of appointment set a general guide of a time commitment between 30-40 days per year. 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.

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 meets once or twice a year and between meetings IAB members remain available to provide advice and counsel when needed.

The IAB is chaired by BP s previous chairman, Peter Sutherland. Its membership in 2015 comprised 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 that could impact BP s business, developments in the Middle East and Latin America, the effects of migration in Europe and the 2016 US election.

How the board works

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 BP values and considering specific issues including health, safety, the environment and reputation.

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 and executes strategy.
- Chairs the executive team (ET), the membership of which is set out on pages 60 to 61.

The senior independent director

Andrew Shilston

- Acts as an internal sounding board for the chairman.
- Serves as intermediary for other directors with the chairman when necessary.
- Is available to shareholders if they have concerns that cannot be addressed through normal channels.
- Leads the chairman s evaluation.

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

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, but instead set a general guide of between 30-40 days per year. The time required of directors may fluctuate depending on demands of BP business and other events, and they are expected to allocate sufficient time to BP to perform their duties effectively and 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 76).

Board diversity

BP recognizes the importance of diversity, including gender diversity, at the board and all levels of the group. We are committed to increasing diversity across our operations and have 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 that 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.

We continue to support the UK government s review of gender diversity on boards, undertaken by Lord Davies in 2011, and maintain an aspiration to increase female representation to 25%. At the end of 2015, there were three female directors (2014 2, 2013 2) on our board of 15. Our nomination committee remains mindful of diversity in considering potential candidates for appointment to the board.

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Committee reports

Audit committee

Chairman s introduction

2015 was another active year for the audit committee. We took the opportunity of the new UK Corporate Governance Code reporting requirements to take a fresh look at the company s risk management processes. This involved reviewing the group s principal risks, considering scenarios that might impact the company s longer-term viability and debating the categorization of what would constitute significant failings and weaknesses in our system of internal control.

The committee continued to build its understanding of BP s business, including how key risks are identified and mitigated and how segments and functions are performing to achieve the group s strategy. To complement the presentations received in the board room, the committee met employees on several site visits including trading floors in Houston and London and the group s cybersecurity monitoring centre.

During 2015 the committee s membership evolved, with our longest-serving member George David retiring in April and Paula Rosput Reynolds joining us in May. I would like to thank George for his insight and challenge during his tenure and to welcome Paula, who brings broad financial and corporate knowledge from her business career. The skills and experience of our committee membership remain strong and I believe that the committee has performed effectively over the year.

Brendan Nelson

Committee chair

Role of the committee

The committee monitors the effectiveness of the group s financial reporting, systems of internal control and risk management and the integrity of the group s external and internal audit processes.

Key responsibilities

- Monitoring and obtaining assurance that the management or mitigation of financial risks is 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, BP s internal financial controls and system 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	
Brendan Nelson (chair)	Member since November 2010; committee chair since April 2011
George David	Member from February 2008 to April 2015
Phuthuma Nhleko	Member since February 2011
Paula Rosput Reynolds	Member since May 2015
Andrew Shilston	Member since February 2012

Brendan Nelson is chair of the audit committee. He was formerly vice chairman of KPMG and president of the Institute of Chartered Accountants of Scotland. Currently he is chairman of the group audit committee of The Royal Bank of Scotland Group plc. 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 and attendance

There were 11 committee meetings in 2015, of which three were carried out by teleconference and five were joint meetings with the SEEAC. All directors attended every meeting for which they were eligible, with the following exceptions:

- George David did not attend the teleconference on 25 February 2015 due to prior commitments.
- Phuthuma Nhleko did not attend the committee meeting on 23 April 2015 due to a clash with the AGM of another company.
- Paula Rosput Reynolds did not attend the committee meeting on 23 September 2015 due to a conflicting board meeting.

Meetings are also attended by the chief financial officer, group controller, chief accounting officer, head of group audit and external auditor.

Activities during the year

Training

The committee held a learning event on changes to the UK Corporate Governance Code and received technical updates during the year from the chief accounting officer on developments in financial reporting and accounting policy.

Financial disclosure

The committee reviewed the quarterly, half-year and annual financial statements with management, focusing on the integrity and clarity of disclosure, compliance with relevant legal and financial reporting standards and the application of critical accounting policies and judgements.

The committee jointly reviewed with the SEEAC whether the *BP Annual Report and Form 20-F 2015* was fair, balanced and understandable and provided the information necessary for shareholders to assess the group s position and performance, business model and strategy. The two committees considered the processes underpinning the compilation and assurance of the report in relation to financial and non-financial management information. Following this joint review, the full board reviewed the report as a whole including tone, balance, language and consistency between the narrative sections and financial statements. Part of the board s evaluation included a review of the company s internal processes that form the group s reporting governance framework.

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Areas of audit committee focus in 2015

*Undertaken jointly with the SEEAC.

Significant areas of accounting judgement considered by the committee during the year

	Key issues/judgements in financial reporting	Audit committee review
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 such as intangible asset balances relating to exploration and appraisal activities as part of the company s quarterly due-diligence process. It also examined the governance framework for the oil and gas reserves process, training for staff and developments in regulations and controls. Significant exploration write-offs during the year were disclosed in the relevant quarter.
Recoverability of asset carrying values	Determination as to whether and how much an asset is impaired involves management judgement and estimates on highly uncertain matters such as future pricing or discount rates. Judgements are also required in assessing the recoverability of overdue receivables and deciding whether a provision is required.	The committee reviewed the discount rates for impairment testing as part of its annual process and examined the assumptions for long-term oil and gas prices and refining margins. It received updates from management at each quarter relating to market forward prices used for impairment testing and considered whether any further impairment indicators were present. The committee also reviewed management s approach to reviewing the carrying values of upstream assets following further falls in market forward prices. Significant impairments during the year were disclosed as non-operating items« in the relevant quarter.
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 when determining the fair value of assets acquired and liabilities assumed, and the level of control which continues to be exercised going forward.	The committee continued to reveiw the accounting for BP s investment in Rosneft including the judgement on whether the group has significant influence over Rosneft. During the year the committee received reports from management and the external auditor that assessed the extent of BP s influence, including participation in decision

		making through the election of two BP nominees to the Rosneft board. It also assessed other factors, including the signing of binding agreements for BP to complete the purchase of a 20% interest in Taas-Yuryakh Neftegazodobycha, a Rosneft subsidiary«.
The group s trading activities	BP uses judgement when estimating the fair value of some derivative instruments in cases where there is an absence of liquid market pricing information for example, relating to supply and trading activities.	The committee received a detailed briefing on the group s trading risk, controls and compliance and visited BP s trading floors in Houston and London. The committee considered the controls in place to prevent unauthorized trading activity and received information on the valuation of the group s derivative instrument and the financial models that are used.
Provisions and contingencies	The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. Most of these decommissioning events are in the long term and the requirements that will have to be met when a removal event occurs are uncertain. Judgement is applied when estimating issues such as settlement dates, technology and legal requirements.	The committee received briefings on the group s decommissioning, environmental remediation and litigation provisioning, including key assumptions used, the governance framework applied (covering accountabilities and controls), discount rates and the movement in provisions over time.

« Defined on page 256.

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Accounting judgements and estimates (continued)

	Key issues/judgements in financial reporting	Audit committee review
Gulf of Mexico oil spill	Judgement was applied during the year around the significant uncertainties over provisions and contingencies relating to the incident.	The committee regularly discussed BP s provisioning for and the disclosure of contingent liabilities relating to the Gulf of Mexico oil spill with management and the external auditors, including as part of the review of BP s stock exchange announcement at each quarter end. The committee examined the provisions booked as a result of the agreements in principle signed in July. In instances where a reliable estimate could not be made of the provision required, the committee considered management s conclusions and monitored 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, 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.

Risk reviews

The group risks allocated to the audit committee for monitoring in 2015 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 information technology risks, its governance of the tax function and the use of financial models including their associated controls framework. The committee further considered the financial group (or principal) risks identified for 2016 and the group s process to assess, mitigate and monitor them. BP s principal risks are listed on page 53. For 2016, the board has agreed that the committee will monitor cybersecurity, trading activities and compliance with applicable laws and regulations.

Other reviews

During the year the committee reviewed succession and development of the group s finance function, including an overview of the demographics and key capability challenges for finance staff. The group s Downstream segment was reviewed to examine the financial performance and strategic priorities of the individual fuels, lubricants and petrochemicals businesses, including key areas of financial risk management.

Internal control and risk management

The committee reviewed the group s system of internal control and risk management throughout the year, holding a joint meeting with the SEEAC to discuss key audit findings and management s actions. The committee reviewed the scope, activity and effectiveness of the group audit function and met privately with the head of group audit and his leadership team during the year.

During the year the committee examined the requirements of the revised UK Corporate Governance Code in relation to the assessment and reporting of longer-term viability, risk management and internal control. The committee looked at key elements of BP s risk management process, including the reporting and categorisation of risk across the group, and jointly with the SEEAC examined what might constitute a significant failing or weakness in the system of internal control. The two committees also reviewed the modelling undertaken to stress test different financial and operational events and considered the appropriate period for which the company was viable.

The committee received quarterly reports on the findings of group audit, on significant allegations and investigations and on key ethics and compliance issues; a joint meeting was held with the SEEAC to discuss the annual report certifying compliance with the BP code of conduct. The two committees also met to discuss future programmes for the group audit and ethics and compliance functions. The committee held a private meeting with the group ethics and compliance officer during the year.

External audit

The external auditors set out their audit strategy, identifying key risks to be considered during the year including longer-term oil and gas prices, the group s cost outlook, the capital framework in a lower oil price environment, discount rate assumptions, considerations around impairments, estimation of oil and gas reserves and resources, decommissioning, valuation of exploration assets, accounting for BP s investment in the Rosneft subsidiary Taas, deferred taxation, estimation of the group s pension obligations, the recovery of receivables and management of change.

The committee received updates during the year on the audit process, including how the auditors had independently considered 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 $51 million (2014 $53 million), of which 6% was for non-assurance work (see Financial statements Note 35). Non-audit or non-audit related assurance fees were $3 million (2014 $5 million). The $2-million reduction in non-audit fees relates primarily to decreases in tax advisory and other assurance services. Non-audit or non-audit related assurance services consisted of tax compliance services, tax advisory services, other assurance 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 two surveys one completed by committee members only and the second by those BP personnel impacted by the audit. The surveys used a set of criteria to measure the auditors performance against the quality commitment set out in their annual audit plan. This included the robustness of the audit process, independence and objectivity, quality of delivery, quality of people and service and value added advice.

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Overall the 2015 evaluation concluded that the external auditor

performance had either improved or remained consistent in key areas with the previous year. Areas with high scores included independence, objectivity and the quality of delivery of the audit. Areas of suggested focus for the auditors included audit team turnover and more liaison between BP s own audit function and the external auditors, with the intent that improved planning could prevent duplication. There was also feedback that the technical knowledge and experience of the audit team remained strong.

The committee held private meetings with the external auditors during the year and the 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 reviewed the group s position on its audit services contract and examined a number of options regarding the timing of tendering for BP s external audit, including the mandatory rotation of the group s audit firm, taking into account the UK Corporate Governance Code and the reforms of the audit market by the Competition and Markets Authority (CMA) and the European Union.

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 and retaining BP s existing audit firm until the conclusion of the term of its current lead partner. The committee intends that the audit contract will be put out to tender in 2016 so that a decision can be taken and communicated to shareholders at BP s AGM in 2017. It is expected that the new audit services contract would be effective from 2018.

BP has complied throughout 2015 with the provisions of The Statutory Audit Services Order 2014, issued by the CMA.

Non-audit services

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 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 for approval of audit-related and non-audit work operates. For services relating to accounting, auditing and financial reporting matters, internal accounting and risk management control reviews or non-statutory audit, the committee has agreed to pre-approve these services up to an annual aggregate level. For all other services which fall under the permitted services categories, approval above a certain financial amount must be sought on 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. The categories of permitted and pre-approved services are outlined in Principal accountants fees and services on page 245.

During the year, the committee reviewed the group s policy on audit-related and non-audit services and it was determined that transfer-pricing services should be moved into the category of work requiring approval from the audit committee chairman or the full committee.

Committee review

The audit committee undertakes an annual evaluation of its performance and effectiveness. In late 2015 the committee used an online survey and externally facilitated interviews to examine governance issues such as committee processes and support, the work of the committee and priorities for change. The review concluded that the committee had

performed effectively. Areas of focus arising from the evaluation included continuing broader segment and business reviews in the committee s 2016 agenda, examining how areas of overlap between the committee and the SEEAC in terms of financial and operational risk could be managed and suggestions for further committee training and committee visits.

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 individual reports on the company s management of highest priority group risks in marine, wells, pipelines, explosion or release at our facilities, and major security incidents. The committee also undertook a number of field visits as well as maintaining its schedule of regular meetings with executive management.

We received final reports from the independent experts we engaged in Upstream (Carl Sandlin) and Downstream (Duane Wilson). They provided valuable insights and advice on many aspects of process safety and we are grateful to them for their work.

We were pleased to welcome Sir John Sawers to the committee in July. John brings valuable experience and insight from his time in government service.

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 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 function, group audit, group ethics and compliance, business integrity and group security. The SEEAC can access any other independent advice and counsel it requires, on an unrestricted basis.

At a joint meeting with the audit committee, the SEEAC 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 that meeting the committees also reviewed the group audit programme for the year ahead to ensure both committees endorsed the coverage. The committees 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.

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Members	
Paul Anderson (chairman)	Member since February 2010; committee chair since December 2012
Alan Boeckmann	Member since September 2014
Frank Bowman	Member since November 2010
Antony Burgmans	Member since February 2004
Cynthia Carroll	Member since June 2007
Ann Dowling	Member since February 2012
John Sawers	Member since July 2015

Meetings and attendance

There were six committee meetings in 2015, plus an additional five joint meetings with the audit committee. All directors attended every meeting for which they were eligible, with the following exceptions:

- Alan Boeckmann did not attend the committee meeting on 13 May 2015 due to prior commitments.
- Cynthia Carroll did not attend the committee meeting on 2 December 2015 due to a conflicting board meeting.

In addition to the committee membership, all SEEAC meetings were attended by the group chief executive, the executive vice president for safety and operational risk (S&OR) and the head of group audit 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.

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 and separate reports on the company s management of risks in marine, wells, pipelines, explosion or release at our facilities and major security incidents. The committee reviewed these risks and their 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 regarding the implementation of the Bly Report recommendations. He formally reported directly to the SEEAC twice in 2015 and presented detailed reports on his work, including reporting on a number of visits made to company operations around the world; he also met in private with the chair and other members of the committee during the year. He reported that all 26 recommendations in the Bly Report were completed by the end of 2015. He gave his final report to the SEEAC in January 2016 and his engagement ceased in February 2016. We thank him for his work with the committee since 2012.

Process safety expert   Downstream

Mr Duane Wilson finalized his engagement with the committee in his role as process safety expert for the Downstream segment. He completed his work with segment management to monitor and advise on the process safety culture and learnings across the segment. He submitted his final report to the SEEAC in January 2015 and completed his engagement in April 2015. The committee thanks him for his work, including on process safety culture.

Reports from group audit, group ethics and compliance and the business integrity functions

The committee received quarterly reports from each of these functions. In addition, both the head of group audit and the group ethics and compliance officer met in private with the chairman and other members of the committee during the year.

Field trips

In June members of the committee visited Trinidad to examine both the offshore facilities (the Cassia platform) and the onshore liquefied natural gas terminal (Atlantic LNG). In November the chairman and other committee members visited operations at the Khazzan gas field development in Oman; in December the chairman and other members of the committee and the board visited the Rotterdam refinery in the Netherlands. In all cases, the visiting committee members received briefings on operations, the status of local operating management system« (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.

Committee review

For its 2015 evaluation, the committee examined its performance and effectiveness through a questionnaire and interviews by external facilitators. Topics covered included the balance of skills and experience among its members, the quality and timeliness of information the committee receives, the level of challenge between committee members and management and how well the committee communicates its activities and findings to the board.

SEEAC focus in 2015

*Undertaken jointly with the audit committee.

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The evaluation results were generally positive. Committee members considered that the committee continued to possess the right mix of skills and background, had an appropriate level of support and received open and transparent briefings from management. The committee considered that the field trips remained an important element of its work, in particular as such trips gave committee members the opportunity to examine how risk management is being embedded in businesses and facilities, including management culture. An area of focus for 2016 will be examining areas of overlap across the committee and the audit committee in terms of how financial and operational risk could be better managed.

Gulf of Mexico committee

Chairman s introduction

The Gulf of Mexico committee continued to oversee the group s response to the Deepwater Horizon accident, ensuring the company fulfils all its legitimate obligations while protecting and defending the interests of the group. The major development in the year was the execution of agreements in principle with the United States and five Gulf states (Alabama, Florida, Louisiana, Mississippi and Texas) on 2 July. These agreements, subject to final court approval of the proposed Consent Decree, resolve all Clean Water Act penalties, natural resource damage claims and various economic loss claims pursued by the Gulf states.

Assuming that the Consent Decree order is approved by the court as anticipated, we intend to recommend to the board that the committee ceases its activities and is stood down at the end of the first quarter of 2016. Reporting of remaining proceedings will be made directly to the board or other committees as appropriate thereafter.

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.

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. This is done in co-ordination with other committees and board oversight.

Members	
Ian Davis (chair)	Member since July 2010; committee chair since July 2010
Paul Anderson	Member since July 2010
Alan Boeckmann	Member since September 2014
Frank Bowman	Member since February 2012
George David	Member from July 2010 to April 2015

George David ceased to be a member of the committee when he retired from the board in April 2015.

Meetings and attendance

There were five committee meetings in 2015, including one by teleconference. All directors attended every meeting for which they were eligible, with the exception of George David who did not attend the committee meeting called at short notice on 9 February 2015 due to a prior commitment.

Gulf of Mexico committee focus in 2015

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Geopolitical committee

Chairman s introduction

I am pleased to report on the work of this committee that was formed during 2015. I have been asked to chair this committee until the 2016 AGM, when I will retire from the board and Sir John Sawers will take the chair.

Antony Burgmans

Committee chair

Role of the committee

The committee monitors the company s identification and management of geopolitical risk.

Key responsibilities

- To monitor the company s identification and management of major and correlated geopolitical risk and to consider reputational as well as financial consequences:
  - Major geopolitical risks are those brought about by social, economic or political events that occur in countries where BP has material investments that can be jeopardized;
  - Correlated geopolitical risks are those brought about by social, economic or political events that occur in countries where BP may or may not have a presence but that can lead to global political instability.
- To review the company s activities in the context of political and economic developments on a regional basis and to advise the board on these elements in its consideration of BP s strategy and the annual plan.

Members	
Antony Burgmans (chair)	Member and committee chair since September 2015
Paul Anderson	Member since September 2015
Frank Bowman	Member since September 2015
Cynthia Carroll	Member since September 2015
Phuthuma Nhleko	Member since September 2015
John Sawers	Member since September 2015
Andrew Shilston	Member since September 2015

Carl-Henric Svanberg and Bob Dudley attend all committee meetings and the executive vice president, strategy and regions and the vice president, government and political affairs attend as required.

Activities during the year

The committee met twice during the year. During those meetings it considered:

- The committee s terms of reference.
- An overview of the company s current geopolitical risks.
- The relationship of the committee with the International Advisory Board.
- The effect of the oil price on geopolitical matters.
- The company s relationships with national oil companies.
- The company s relationships in specific countries and regions.

Chairman s and nomination committees

Chairman s introduction

I am pleased to report on the two board committees that I chair. Both actively sought to develop the membership of the board and its governance during the year.

Carl-Henric Svanberg

Committees chair

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 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 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 seven times in the year. During the year the committee:

Monitored the progress of the Gulf of Mexico litigation and, in particular, considered the proposals which led to the Agreements in Principle to settle federal and state claims and claims made by local government entities.

Reviewed BP s strategy in light of the continuing decline in oil prices.

Considered the succession and organization of the executive team.

Evaluated the performance of the chairman and chief executive.

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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 non-executive directors.

Members	
Carl-Henric Svanberg (chair)	Member since September 2009; committee chair since January 2010
Paul Anderson	Member since April 2012
Cynthia Carroll	Member from May 2011 to May 2015
Antony Burgmans	Member since May 2011
Ann Dowling	Member since May 2015
Ian Davis	Member since August 2010
Brendan Nelson	Member since April 2012
Andrew Shilston	Member since May 2015, but attended previously as senior independent director

During the year Ann Dowling and Andrew Shilston joined the committee and Cynthia Carroll stood down.

Activities during the year

In 2014 the committee had previously identified Paula Reynolds and Sir John Sawers as candidates to join the board; they then both joined in May 2015. With the total number of the board standing at 15, the committee met once during the year to carry out a broader review of board composition and skills in light of BP s strategy and the potential sequencing of board retirements. The committee focused on non-executive membership of the board as executive succession is considered in the chairman s committee.

By most standards the board would be considered large. The committee notes that as Antony Burgmans and Phuthuma Nhleko will be standing down at the 2016 AGM, the optimum size of the board should be considered together with the skills relevant for the board and its committees. The committee was of the view that the current board is well balanced with an appropriate breadth of skills. Industry experience needs to be maintained as does the balance between former chief executives and those with different functional and sectoral expertise. The need to maintain diversity in all forms remains a major consideration for a board in a global business and the committee reviewed how potential appointments meet the board s aspirations on diversity, inclusiveness and meritocracy. The committee also remained mindful of BP s commitment to Lord Davies report and work on women on boards.

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Directors remuneration report

The Chairman s Statement (which forms part of the Directors Remuneration Report) is located on pages 22-23. Please refer to this for an overview from Professor Dame Ann Dowling on the performance and pay outcomes for 2015.

2015 annual report on remuneration

Highlights of the year

Strong safety and operational performance in a difficult environment

Responded early and decisively to lower oil price environment.

Excellent safety standards with continuous improvement over the past three years, leading to improvements in reliability and operations.

Strong operating cash flow« and underlying replacement cost profit relative to plan.

Net investment (organic)« managed aggressively to reflect lower for longer oil price environment.

Executive directors pay outcomes reflect strong operating performance relative to plan.

Alignment between executives and shareholders with the majority of executive director remuneration paid in equity with lengthy retention requirements.

Remuneration policy

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. As shown below, BP s strategy is reflected in the measures adopted by the committee in 2016 for the executive directors and the metrics and targets are designed to assess performance against that strategy. Net investment (organic) has been removed as a measure for 2016. The same measures and targets are used for the wider management. A summary of the policy is located on pages 88-89 and the full policy is available at *bp.com/remuneration* and is set out in the *BP Annual Report and Form 20-F 2013.* The committee has again 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 consider this on the next occasion that it reviews the remuneration policy. Separate sections of this report contain information pertaining to executive and non-executive directors. The remuneration of executive directors is set by the remuneration committee under delegated powers from the board. The committee makes a recommendation to the board for the remuneration of the chairman. The remuneration of non-executive directors is set by the board based on a recommendation from the chairman, the group chief executive and the company secretary.

Strategic priorities

2016 bonus and equity plans supporting BP s strategic priorities

Short term: annual bonus		Long term: performance share plan
Safety and operational risk	Value	Relative total shareholder return
Loss of primary containment	Operating cash flow	Cumulative operating cash flow
Process safety tier 1 events	Underlying replacement cost profit	Strategic imperatives:
Recordable injury frequency	Corporate and functional costs	Relative reserves replacement ratio
	Major project delivery	Safety and operational risk
		Major project delivery

Creating long-term shareholder value

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Executive directors

Total remuneration summary 2015

The table below shows the total remuneration received by executive directors in 2015 and reflects the following:

Salary no increases were granted for 2015, in line with the group-wide salary freeze. The last increase was in July 2014.

Annual bonus the key focus for 2015 was safe and reliable operations, delivery of strong operating cash flow relative to plan and major projects within the year. This resulted in **a final overall group score of 1.70 but limited to 1.50 for executive directors**.

Deferred bonus 2012 deferred bonus was conditional on safety and environmental sustainability performance over the period 2013 through to 2015. There was strong and consistent delivery against this hurdle and **2012 deferred and matching 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 major project delivery«. TSR performance was third amongst the oil majors. There was strong performance related to operating cash flow and the strategic imperatives. On a preliminary assessment **77.6% of the 2013-2015 award is 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 the company match to retirement savings plans and any cash paid in lieu. The UK requirement overstates the true increase in value of Bob Dudley s US pension (see page 82 for explanation).

Single figure table of remuneration of executive directors in 2015 (audited)

Remuneration is reported in the currency received by the individual

	Bob Dudley thousand		Dr Brian Gilvary thousand	
Annual remuneration	**2015**	2014	**2015**	2014
Salary	**$1,854**	$1,827	**£732**	£721
Annual cash bonus[a]	**$1,391**	$1,005	**£549**	£396
Benefits	**$119**	$114	**£53**	£51
Total	**$3,364**	$2,946	**£1,334**	£1,168
Vested equity				
Deferred bonus and match[b]	**$2,603**	$3,401	**£1,272**	£0

Performance shares	**$7,116**[c]	$7,020[d]	**£2,223**[c]	£2,185[d]
Total	**$9,719**	$10,421	**£3,495**	£2,185
Total remuneration	**$13,083**	$13,367	**£4,829**	£3,353
Pension				
Pension and retirement savings value increase[e]	**$6,519**	$3,023	**£0**	£21
Cash in lieu of future accrual	**N/A**	N/A	**£256**	£252
Total including pension	**$19,602**	$16,390	**£5,085**	£3,626

[a] This reflects the amount of bonus paid in cash with the deferred portion as set out in the conditional equity table below.

[b] Value of vested deferred bonus and matching shares. The amounts reported for 2015 relate to the 2012 annual bonus deferred over three years, which vested on 9 February 2016 at the market price of £3.34 for ordinary shares and $28.95 for ADSs and include re-invested dividends on shares vested. The amounts reported for 2014 relate to the 2011 annual bonus.

[c] Represents the assumed vesting of shares in 2016 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 2015 which was £3.72 for ordinary shares and $33.81 for ADSs. The final vesting will be confirmed by the committee in second quarter 2016 and provided in the 2016 Directors remuneration report.

[d] In accordance with UK regulations, in the 2014 single figure table, the performance outcome value was based on an estimated vesting at an assumed share price of £4.27 for ordinary shares and $40.74 for ADSs. In May 2015, after the external data became available, the committee reviewed the relative reserves replacement ratio position and assessed that the group was in first place relative to the other oil majors. This resulted in an adjustment to the final vesting from 60.5% to 63.8%. On 7 May 2015, 167,824 ADSs for Bob Dudley and 478,090 shares for Brian Gilvary vested at prices of $41.83 and £4.57 respectively. The 2014 values for the total vesting have increased by $628,746 for Bob Dudley and £280,827 for Brian Gilvary.

[e] Represents (1) the annual increase net of inflation in accrued pension multiplied by 20 as prescribed by UK regulations, and (2) in the case of Bob Dudley only, the aggregate value of the company match under his US retirement savings arrangements. Full details are set out on page 82. In Bob Dudley s case, the 2014 amount has been restated to reflect the revised disclosure of Mr Dudley s participation in the US retirement savings arrangements.

Conditional equity to vest in future years, subject to performance

		Bob Dudley		Dr Brian Gilvary	
Deferred bonus in respect of bonus year		**2015**[a]	2014	**2015**[a]	2014
Total deferred bonus	Value (thousand)	**$2,781**	$2,010	**£1,097**	£793
Total deferred converted to shares	Shares	**551,784**	294,108	**318,042**	176,576
Total matched shares	Shares	**551,784**	294,108	**318,042**	176,576
Vesting date		**Feb 2019**	Feb 2018	**Feb 2019**	Feb 2018
Release date[b]		**Feb 2022**	Feb 2021	**Feb 2022**	Feb 2021
Performance share element		**2015-2017**	2014-2016	**2015-2017**	2014-2016
Potential maximum shares		**1,501,770**	1,304,922	**685,246**	605,544
Vesting date		**Feb 2018**	Feb 2017	**Feb 2018**	Feb 2017
Release date		**Feb 2021**	Feb 2020	**Feb 2021**	Feb 2020

[a] It is anticipated that the 2015 deferred bonus award will be made in May 2016.

[b] Deferred shares are released at vesting with the exception of matched shares which normally have a further three-year retention period.

« Defined on page 256.

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Total remuneration in more depth

The committee, in seeking a fair outcome for pay, has for many years sought to ensure that variable pay is based primarily on true underlying performance and is not driven by factors over which the directors have no control. Accordingly, the committee normalizes for changes in oil and gas price and refining margins. Other factors such as major divestments and

contributions to the Gulf of Mexico restoration made in the year are also taken into consideration. In the light of the substantial drop in the price of oil during the three-year plan, the committee has been focused on ensuring that its approach to normalization has been consistent with our previous approach.

Salary and benefits

Base salary

No increases were granted to executive directors for 2015, in line with the group-wide salary freeze, therefore the 2015 salaries remained unchanged from 1 July 2014: $1,854,000 for Bob Dudley and £731,500 for Dr Brian Gilvary.

2016 implementation

The committee reviewed executive directors salaries in January 2016. Given the continuing low oil price environment, no increases will be applied to executive directors salaries for 2016.

Benefits

Executive directors received car-related benefits, security assistance, insurance and medical benefits.

Annual bonus

Framework

The committee determined performance measures and their weightings for the 2015 annual bonus at the beginning of the performance year. The 2015 bonus plan was set in the context of the group s strategy and short-term imperatives. It focused on two key priorities: safety and value. Targets for each measure were challenging but realistic and were set in the context of the current price and industry environment. Targets for the value measures were based upon the annual plan. Threshold and maximum were set on a linear scale around the target.

Continued improvement in safety performance remains a key focus area and a group priority, particularly given the need to simplify the business. Safety made up 30% of total bonus. Safety measures included loss of primary containment, tier 1 process safety events« and recordable injury frequency. Challenging targets were set, both to build on the improving trend of the last three years and to continue to reduce the number of safety events.

[a] Adjusted in accordance with the treatment of the LOPC KPI on page 20. Full LOPC is 235.

[b] Recordable injury frequency excludes biofuels.

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Value measures made up 70% of total bonus. In order to simplify and reflect both the current short-term imperatives and the 2015 priorities in the group s annual plan, the number of value measures was reduced from six in 2014 to five in 2015. These measures were more heavily weighted on operating cash flow and underlying replacement cost profit. The economic environment was taken into account by looking at capital and cost discipline and these were reflected through two measures net investment (organic) and corporate and functional cost management. As in previous years, delivery of major projects remained a key focus area.

Bob Dudley and Dr Brian Gilvary s annual bonus was based 100% on these group-wide measures. Under the policy, one third of the total bonus is paid in cash. A director is required to defer a further third in BP shares and the final third is paid either in cash or voluntarily deferred in BP shares at the individual s election. 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.

2015 outcomes

In January 2016, the committee considered the group s performance during 2015 against the measures and targets set out in the 2015 annual cash bonus table.

As the table reflects, BP had an excellent year for safety and operational performance in a difficult environment.

The company s decision in late 2014 to plan for a lower for longer oil price meant that the leadership acted early and decisively to respond to the low oil price environment. Strong and continually improving safety standards have led to higher reliability and improved operations, contributing directly to better financial outcomes. Cost reduction and net investment have been managed so as not to compromise future growth. Major projects have been delivered on time, improving forthcoming performance.

Safety performance was again very encouraging, resulting in maximum scores for all three measures tier 1 process safety events, loss of primary containment and recordable injury frequency.

Operating cash flow for the company was $19.1 billion, well ahead of the board s approved plan of the target of $17.2 billion. This target was normalized upwards since the actual oil price during the year was higher than original plan assumptions. Underlying replacement cost profit of $5.9 billion was also significantly ahead of the target of $4.2 billion, again normalized similar to the above. Through greater simplification and efficiency across all functions, corporate and functional costs were reduced by 17.6% against a targeted reduction of 5.9%. Capital discipline was demonstrated through a reduction in the net investment (organic) of 27% against a planned reduction of 18%. Four major projects were successfully delivered in 2015, as planned.

Based on these results, the overall group performance score was 1.91. The committee, as is its normal practice, considered this result in the context of the performance of the group, shareholder feedback, input from the board and other committees, as well as the circumstances in the wider environment. Overall, management delivered very well in terms of what they could control. The committee agreed with the group chief executive s view that the dramatic dynamics in the market during the year also needed to be recognized. He proposed a lower score and the committee agreed that this reflected a balanced assessment of the year. A final group score of 1.70 was agreed and applied to BP s wider management group. In the case of executive directors, our approved policy limits bonus to a group score of 1.50.

The overall annual bonus for executive directors was determined by multiplying the reduced score of 1.5 by the on-target bonus level of 150% of salary. Both Bob Dudley and Dr Brian Gilvary deferred two thirds of their 2015 annual bonus. As a result Bob Dudley s and Dr Brian Gilvary s bonuses, including the portion deferred, are shown below.

Annual bonus summary

	Overall bonus	Paid in cash	Deferred in BP shares
Bob Dudley	$4,171,500	$1,390,500	$2,781,000
Dr Brian Gilvary	£1,645,875	£548,625	£1,097,250

2016 implementation

For 2016, 100% of Bob Dudley s and Dr Brian Gilvary s bonus will be based on group results.

For the 2016 annual bonus the committee will continue to focus on the two overall themes of safety and value. Safety will continue to have a 30% weight in the overall bonus plan. The value measures are key to short-term performance within the group and will have an overall weight of 70%.

Continued improvement in safety remains a group priority and is fully reflected in the measures. As in 2015, the safety targets are anchored on a realistic and achievable improvement from the average of the previous three years.

The value measures have been decreased from 5 in 2015 to 4 in 2016, increasing the weight on operating cash flow and underlying replacement cost profit and removing the net investment measure. Targets for each measure are challenging but realistic and have been set in the context of the current environment. As usual they will be normalized at year end to reflect changes in oil and gas price and refining margins.

Safety and value targets will be disclosed retrospectively in the 2016 remuneration report to the extent that they are no longer considered commercially sensitive. The full set of 2016 short-term measures are set out in the diagram on page 76.

Deferred bonus

2015 outcomes

Both Bob Dudley and Dr Brian Gilvary deferred two thirds of their 2012 annual bonus in accordance with the terms of the policy then in place.

The three-year performance period concluded at the end of 2015. 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 2013-15 safety performance showed steady improvement on a range of measures. 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 2012 deferred bonus was approved, as shown in the following table (as well as in the single figure table on page 77).

2012 deferred bonus vesting

Name	Shares deferred	Vesting agreed	Total shares including dividends	Total value at vesting
Bob Dudley	458,760	100%	539,424	$2,602,721
Dr Brian Gilvary	315,260	100%	380,905	£1,272,223

Details of the deferred bonus awards made to the executive directors in early 2015, in relation to 2014 annual bonuses, were set out in last year s report. A summary of these awards is included on page 86.

2016 implementation

The committee has determined that the safety and environmental sustainability hurdle will continue to apply to shares deferred from the 2015 bonus. All matched shares that vest in 2019 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 2022. This further reinforces long-term shareholder alignment and the nature of the group s business.

« Defined on page 256.

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Performance shares

Framework

Performance shares were conditionally awarded to each executive director in 2013. 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. 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 three strategic imperatives: relative reserves replacement ratio (RRR), safety and operational risk (S&OR) and major projects delivery, all equally weighted. Performance against each of these measures was designed to be aligned with group strategy and key performance indicators (KPIs). Some measures appear in both the annual cash bonus and performance shares scorecards as they serve to track in-year performance as well as growth/improvement over a three-year period.

Relative TSR represents the change in value of a BP shareholding between the average of the fourth quarter of 2012 and the fourth quarter of 2015 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 2013-15 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 2013 and equals 100%, 70% and 35% respectively. This reflects the approved rules applicable to the 2013-2015 plan. No shares would vest for fourth or fifth place.

Operating cash flow represented a further one third of the award. BP s approved policy specifically states that: operating cash flow has been identified as a core measure of strategic performance of the company. Targets reflected agreed plans and normal operating assumptions.

For S&OR, improvement targets were set. For major project delivery, the committee set a number of projects expected to be delivered over three years. In reviewing project delivery the committee reviews the cost and any delays to the original schedule.

2015 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. The results are summarized in the table below.

Relative TSR, representing a third of the award, was in third place versus the comparator group resulting in 35% vesting. Consequently 11.7% of the overall shares for this measure will vest. The significant weight associated with this measure aligns the actual value delivered to executive directors with that to shareholders.

Operating cash flow represented a further one third of the award. In considering measures and targets for performance share awards BP has historically adopted a normalized or like-for-like approach reflecting changes in oil and gas prices. This avoids windfall gains or penal losses in periods of extreme volatility. The target set in 2013 for 2015 operating cash flow was $35 billion based on the plan assumptions relating to oil and gas price and refining margins at that time. This target was reviewed at the start of 2015 in the light of divestments and plan assumptions relating to environment, principally oil and gas prices and refining margins. Consistent with its previous practice the committee normalized the operating cash flow target. Based on the above assumptions, adjusting for major divestments and for contributions to the Gulf of Mexico restoration made in the year, the operating cash flow target was set at $17.7 billion. A scale comprising threshold and maximum figures was set around the target on a linear basis. The actual 2015 operating cash flow was $19.1 billion, equalling the maximum set and resulting in vesting of 33.3% of all shares for this measure.

[a] This represents a preliminary assessment.

[b] Adjusted in accordance with the treatment of the LOPC KPI on page 20. Full LOPC is 235.

[c] RIF excludes biofuels.

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Strategic imperatives represented the final third. These included relative RRR, S&OR, and major project delivery, each weighted equally.

Preliminary assessment of BP s relative RRR indicated a positive outcome with an expected first place amongst the comparator group. The final ranking will be determined once the actual results for 2015 have been published by other comparator companies. For the purposes of this report, and in accordance with the UK regulations, first place has been assumed. Any adjustment to this will be reported in next year s annual report on remuneration. Based on a provisional first place assessment, 11.1% of the overall shares for this measure are expected to vest.

S&OR has improved significantly over the 2013-15 period, with a downward trend over the period in tier 1 process safety events (53%), recordable injury frequency (30%), and loss of primary containment (28%). The operating management system continued to mature and there has been a continual rise in assessed conformance levels. Consequently 10.4% of overall shares will vest for the safety measures.

Fifteen major projects were delivered over the three years well ahead of plan and resulting in full vesting for this measure. As a result, 11.1% of overall shares will vest.

As in past years, the committee also considered the true underlying operational and financial 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 77.6% vesting was a fair reflection of the overall performance, pending confirmation of the relative reserves replacement ratio result. This will result in the vesting shown in the table below.

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 2019.

2013-2015 performance shares preliminary outcome

	Shares awarded	Shares vested including dividends	Value of vested shares
Bob Dudley	1,384,026	1,262,868	$7,116,261
Dr Brian Gilvary	637,413	597,628	£2,223,176

2012-2014 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 2012-2014 performance shares element. In May 2015 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 11.1% of shares would vest for this performance measure as opposed to 7.8% for second place. This resulted in a final overall vesting of 63.8% (versus 60.5% as preliminarily outlined in the 2014 report) for the entire award. This change is reflected in the single figure table on page 77.

2016 implementation

Consistent with application of policy and our previous approach, shares are expected to be awarded in March 2016 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. These will be awarded under the performance share element of the EDIP and will be subject to a three-year performance period. Those shares that vest are subject, after tax, to an additional three-year retention period. The 2016-2018 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; and major project delivery, all equally weighted.

These measures continue to be aligned with BP s strategic priorities of safe, reliable and compliant operations, competitive project execution, disciplined financial choices and sources of future growth. The committee agreed targets and scales for measures that will be used to assess performance at the end of the three-year performance period and these will be disclosed retrospectively, to the extent that they are no longer commercially sensitive.

For S&OR the committee will study annual results based on outcomes from the annual cash bonus for the period 2016 to 2018 and make a determination of the three-year outcome. Similarly for operating cash flow the committee, at the end of the period, will make a determination of the three-year outcome by comparing the cumulative actual annual results against the cumulative actual annual targets.

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.

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

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Pension

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 and retirement savings

Bob Dudley participates in US pension and retirement savings plans. These involve a combination of tax-qualified and non-qualified plans, consistent with applicable US tax regulations. Benefits payable under non-qualified plans are unfunded and therefore paid from corporate assets.

Details of the pension plans in which Mr Dudley participates are as follows. 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) who participated in these predecessor company pension plans. The TNK-BP Supplemental Retirement Plan is 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 (ECRP) 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 Internal Revenue Service (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 non-qualified supplemental plan which provides a benefit 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.

Mr Dudley also participates in US retirement savings plans on the same terms as those available to all eligible US employees. These savings plans provide benefits to employees on or after their retirement. These are provided through a tax-qualified plan and a non-qualified plan. The BP Employee Savings Plan (ESP) is a US tax-qualified section 401(k) plan to which both Mr Dudley and BP contribute within limits set by US tax regulations. The BP Excess Compensation (Savings) Plan (ECSP) is a non-qualified, unfunded plan under which BP provides a notional match in respect of eligible pay that exceeds the limit under the ESP. Mr Dudley does not contribute to the ECSP. For the purposes of the plans, eligible pay includes base salary, cash bonus and bonus deferred into a compulsory or voluntary award under the deferred matching element of the EDIP. Under both plans, participants are entitled to make investment elections, involving an investment in the relevant fund in the case of the ESP and a notional investment (the return on which would be delivered by BP under its unfunded commitment) in the case of the ECSP.

These retirement savings arrangements pre-date Mr Dudley s appointment as a director and are grandfathered as a pre-27 June 2012 obligation for the purposes of the remuneration policy approved by shareholders in April 2014. The cost to the company has been fully provided for within the amounts disclosed for pensions and other post-retirement benefits in the financial statements. Previous remuneration reports have not disclosed details of Mr Dudley s participation in these arrangements but following a review, BP has determined that disclosure of the company s contribution to these plans should now be included in this report.

UK pension

Dr Brian Gilvary participates in a UK final salary pension plan in respect of service prior to 1 April 2011. This plan 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 plan who have exceeded the annual allowance or lifetime allowance under UK regulations, and have chosen to cease future accrual of pension. Dr Gilvary falls into this category and in 2015 received a cash supplement 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 benefit for service up to 30 November 2006, and subject to such reduction as the plan actuary certifies in respect of the period of service after 1 December 2006. The plan 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 his leaving date.

2015 outcomes

Mr Dudley participates in the US pension and retirement savings plans described above. The pension plans are aimed at an overall accrual rate of 1.3% of final earnings (which include salary and bonus), for each year of service. In 2015, Mr Dudley s accrued pension increased, net of inflation, by $309,000. This increase has been reflected in the single figure table on page 77 by multiplying it by a factor of 20 in accordance with the requirements of the UK regulations (giving $6,176,000). The committee will continue to make the required disclosures in accordance with the UK regulations; however, given the issues and differences set out below, it would note that around 14 would be a typical annuity factor in the US compared with the factor of 20 upon which the UK regulations are based.

In relation to the retirement savings plans, Mr Dudley made pre-tax and post-tax contributions in 2015 to the ESP totalling $26,500 (2014: $26,000). For 2015 the total value of BP matching contributions in respect of Mr Dudley to the ESP and notional matching contributions to the ECSP was $341,000, 7% of eligible pay (2014: $374,000, 7% of eligible pay). After adjusting for investment gains within his accumulating unfunded ECSP account (aggregating the unfunded arrangements relating to his overall service with BP and TNK-BP) the amount included in the single figure table on page 77 is $343,000. The equivalent figure for 2014 has been restated (an increase of $427,000) to reflect the revised disclosure treatment.

Dr Gilvary participates in the UK pension arrangements described above. In 2015 Dr Gilvary s accrued pension did not increase and therefore net of inflation it reduced. In accordance with the requirements of the UK regulations, the value shown in the single figure table on page 77 is zero. He has exceeded the lifetime allowance under UK pension legislation and, in accordance with the policy, receives a cash supplement of 35% of salary, which has been separately identified in the single figure table on page 77.

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.

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Remuneration committee

Members	
Professor Dame Ann Dowling (chair)	Member since July 2012; committee chair since May 2015
Antony Burgmans	Member since May 2009; committee chair from May 2011 to May 2015
Alan Boeckmann	Member since May 2015
George David	Member from May 2009 to April 2015
Ian Davis	Member since July 2010
Andrew Shilston	Member since May 2015

2015 was a year of transition for the committee as the membership evolved. Dame Ann Dowling took the chair from Antony Burgmans after the May meeting. George David stood down from the board in April, Alan Boeckmann and Andrew Shilston joined the committee.

Carl-Henric Svanberg and Bob Dudley attend meetings of the committee except for matters relating to their own remuneration. The group chief executive (GCE) is consulted on the remuneration of the other executive director and the executive team and on matters relating to the performance of the group. The group human resources director normally attends meetings of the committee, and other executives may attend relevant parts of those 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.

Key tasks of the remuneration committee

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 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 means regulations made from time to time under the Companies Act 2006, the UK Corporate Governance Code adopted by the Financial Reporting Council and the UK Listing Authority s Listing Rules in relation to the remuneration of directors of quoted companies.

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 2015 meetings

	Jan	May	Jul	Sept	Dec
Strategy and policy					
Review and approve directors remuneration report (DRR) for 2015 AGM	■				
Consider DRR votes from 2015 AGM		■			
Review committee tasks and operation					■
Review of BP remuneration strategy		■			
Salary review					
Executive directors	■				■
Executive team and leadership group	■				■
Annual bonus					
Assess performance	■		■		■
Determine bonus for 2014	■				
Agree measures and targets for 2015	■				
Review measures for 2016			■	■	
Consider measures and targets for 2016					■
Long-term equity plan					
Assess performance	■	■	■		■
Determine vesting of 2012-2014 plan	■	■			
Determine vesting of 2011 deferred bonus	■				
Agree measures, targets and awards for 2015-2017 plan	■				
Review measures for 2016-2018 plan			■	■	■
Consider measures and targets for 2016-2018 plan					■
Other items					
Review principles for target setting		■	■	■	■

and disclosure
Other issues as required
Independence and advice

Independence

The board considers all committee members to be independent with no personal financial interest, other than as shareholders, in the committee s decisions.

Advice

During 2015 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 with experience of advising a number of companies in the UK and Europe. He is engaged directly by the committee. Advice and services on particular remuneration matters were also received from other external advisers appointed by the committee.

Willis 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 2015 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 £130,000

Willis Towers Watson £38,309

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Committee review

The board evaluation process for 2015 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 January 2016. As part of the broader external evaluation described elsewhere, any issues relating to the committee or its work were discussed by the board in January 2016.

Shareholder engagement

The committee values its dialogue with major shareholders on remuneration matters. During the year, the committee s chair and the company secretary held individual meetings with several larger 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 of the board which took place in March 2015, and a regular 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.

Against the background of the encouraging vote that had taken place at the April AGM and the dialogue with shareholders around the meeting, the committee has noted the shareholders support for the approach taken regarding retrospective disclosure of targets but notes they wish for still more.

Accordingly we have this year added additional retrospective disclosure on targets and scales for both annual bonus and long-term performance shares. During the year, Dame Ann Dowling met with a number of the larger shareholders and those who advise them. These have been constructive meetings and they will be built on in the current year, to aid the preparation of a revised remuneration policy for the chairman and the executive directors to be presented to shareholders at the AGM in 2017.

The board s annual report on remuneration was approved by shareholders at the 2015 AGM. The votes on the report are shown below.

2015 AGM directors remuneration report vote results

Year	% vote for	% vote against	Votes withheld
2015	88.8%	11.2%	305,297,190

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.

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 2015 are shown below.

Director	Appointee company	Additional position held at appointee company	Total fees
Bob Dudley	Rosneft[a]	Director	0

[a] Bob Dudley holds this appointment as a result of the company s shareholding in Rosneft.

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 seven 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 seven-year period were £99.06 (2014: £107.45) and £190.42 (2014: £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	$8,057	0	0
2011	Dudley	$8,439	67	16.7
2012	Dudley	$9,609	65	0
2013	Dudley	$15,086	88	45.5
2014	Dudley	$16,390	73	63.8
2015	Dudley	$19,602	100	77.6

[a] Total remuneration figures include pension. For Bob Dudley this has been restated since 2010 in accordance with the principles explained on page 82, to include the value of the company s contribution to his US retirement savings arrangements. The total figure is also affected by share vesting outcomes and these numbers represent the actual outcome for the periods up to 2011 or the adjusted outcome in subsequent years where a preliminary assessment of the performance for EDIP was made. For 2015, the preliminary assessment has been reflected.

[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.

Relative importance of spend on pay (million)

[a] Total remuneration reflects overall employee costs. See Financial statements Note 34 for further information.

[b] Capital investment reflects organic capital expenditure«.

[c] See Financial statements Note 30 for further information.

[d] Dividends includes both scrip dividends as well as those paid in cash. See Financial statements Note 9 for further information.

Percentage change in CEO remuneration

Comparing 2015 to 2014	Salary	Benefits	Bonus
% change in CEO remuneration	1.5%	4.4%	38.4%
% change in comparator group remuneration	0%[a]	0%[b]	27.9%

a

The comparator group comprises some 31% of BP s global employee population being professional/managerial grades of employees based in the UK and US and employed on more readily comparable terms.

[b] There was no change in employee benefits level.

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 22 February 2016 from the directors interests shown below plus the assumed vesting of the 2013-2015 performance shares and is consistent with the figures reported in the single figure table on page 77.

	Appointment date	Value of current shareholding	% of policy achieved
Bob Dudley	October 2010	$12,478,540	135
Dr Brian Gilvary	January 2012	£3,559,733	97

The committee is satisfied that all executive directors shareholdings meet the policy requirement.

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 (DTRs) as at the applicable dates.

Current directors	Ordinary shares or equivalents at 1 Jan 2015	Ordinary shares or equivalents at 31 Dec 2015	Change from 31 Dec 2015 to 22 Feb 2016	Ordinary shares or equivalents total at 22 Feb 2016
Bob Dudley[a]	738,858	1,554,198	285,366	1,839,564
Dr Brian Gilvary	545,217	903,856	201,710	1,105,566

[a] 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	Performance	Change from	Performance

	shares at 1 Jan 2015	shares at 31 Dec 2015	31 Dec 2015 to 22 Feb 2016	shares total at 22 Feb 2016
Bob Dudley[a]	5,227,500	5,536,950	(458,760)	5,078,190
Dr Brian Gilvary	2,375,957	2,789,921	(315,260)	2,474,661

[a] Held as ADSs.

At 22 February 2016, the following directors held the numbers of options under the BP group share option schemes over ordinary shares or their calculated equivalent set out below. None of these are subject to performance conditions. Additional details regarding these options can be found on page 87.

Current director	Options
Dr Brian Gilvary	504,191

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 22 February 2016, all directors and other members of senior management as a group held interests of 17,529,149 ordinary shares or their calculated equivalent, 8,761,779 performance shares or their calculated equivalent and 6,039,841 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 60-61 for further information.

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Deferred shares (audited)[a]

				Deferred share element interests			Interests vested in 2015 and	
				Potential maximum deferred shares			Number of ordinary	
		Performance	Date of award of	At 1 Jan	Awarded	At 31 Dec	shares	
Bonus year	Type	period	deferred shares	2015	2015	2015	vested	Vesting date
2011	Comp	2012-2014	08 Mar 2012	109,206			126,444[c]	11 Feb 2015
	Vol	2012-2014	08 Mar 2012	109,206			126,444[c]	11 Feb 2015
	Mat	2012-2014	08 Mar 2012	218,412			252,894[c]	11 Feb 2015
2012	Comp	2013-2015	11 Feb 2013	114,690		114,690	134,856[c]	9 Feb 2016
	Vol	2013-2015	11 Feb 2013	114,690		114,690	134,856[c]	9 Feb 2016
	Mat	2013-2015	11 Feb 2013	229,380		229,380	269,712[c]	9 Feb 2016
2013[d]	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	147,054		
	Vol	2015-2017	11 Feb 2015		147,054	147,054		
	Mat	2015-2017	11 Feb 2015		294,108	294,108		
2011	DAB[f]	2012-2014	15 Mar 2012	73,624			84,491[c]	15 Jan 2015
2012	Comp	2013-2015	11 Feb 2013	78,815		78,815	95,226[c]	9 Feb 2016
	Vol	2013-2015	11 Feb 2013	78,815		78,815	95,226[c]	9 Feb 2016
	Mat	2013-2015	11 Feb 2013	157,630		157,630	190,453[c]	9 Feb 2016
2013[d]	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	88,288		
	Vol	2015-2017	11 Feb 2015		88,288	88,288		
	Mat	2015-2017	11 Feb 2015		176,576	176,576		
ecutive directors								
2011	Comp	2012-2014	08 Mar 2012	80,652			95,196[c]	11 Feb 2015
	Vol	2012-2014	08 Mar 2012	80,652			95,196[c]	11 Feb 2015
	Mat	2012-2014	08 Mar 2012	161,304			190,393[c]	11 Feb 2015
2012	Comp	2013-2015	11 Feb 2013	80,648		80,648	97,441[c]	9 Feb 2016
	Vol	2013-2015	11 Feb 2013	80,648		80,648	97,441[c]	9 Feb 2016
	Mat	2013-2015	11 Feb 2013	107,531[g]		107,531[g]	129,922[c]	9 Feb 2016
2013[d]	Comp	2014-2016	12 Feb 2014	100,563		100,563		
	Mat	2014-2016	12 Feb 2014	33,521[g]		33,521[g]		
2011	Comp	2012-2014	08 Mar 2012	91,638			106,104[c]	11 Feb 2015
	Vol	2012-2014	08 Mar 2012	91,638			106,104[c]	11 Feb 2015
	Mat	2012-2014	08 Mar 2012	91,638[g]			106,104[c]	11 Feb 2015

2012	Comp	2013-2015	11 Feb 2013	97,278	97,278	114,384[c]	9 Feb 2016
	Vol	2013-2015	11 Feb 2013	97,278	97,278	114,384[c]	9 Feb 2016
	Mat	2013-2015	11 Feb 2013	32,424[g]	32,424[g]	38,124[c]	9 Feb 2016

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 15 January 2015, 11 February 2015 and 9 February 2016 were £3.93, £4.46 and £3.34 respectively and for ADSs on 11 February 2015 and 9 February 2016 were $40.35 and $28.95 respectively.

[d] The face value has been calculated using the market price of ordinary shares on 12 February 2014 of £4.87.

[e] The market price at closing of ordinary shares 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 2015		
			Potential maximum performance shares[a]			Number of ordinary		£
	Performance period	Date of award of performance shares	At 1 Jan 2015	Awarded 2015	At 31 Dec 2015	shares vested	Vesting date	Face value of the award
ob Dudley[b]	2012-2014	08 Mar 2012	1,343,712			1,006,944[c]	7 May 2015[d]	
	2013-2015	11 Feb 2013	1,384,026		1,384,026	1,262,868[c]	May 2016	
	2014-2016[e]	12 Feb 2014	1,304,922		1,304,922			6,354,970
	2015-2017[e]	11 Feb 2015		1,501,770	1,501,770			6,697,894
r Brian ilvary	2012-2014	08 Mar 2012	624,434			478,090[c]	7 May 2015[d]	
	2013-2015	11 Feb 2013	637,413		637,413	597,628[c]	May 2016	
	2014-2016[e]	12 Feb 2014	605,544		605,544			2,948,999
	2015-2017[e]	11 Feb 2015		685,246	685,246			3,056,197
ormer executive irectors								
ain Conn	2012-2014	08 Mar 2012	660,633			505,805[c]	7 May 2015[d]	
	2013-2015	11 Feb 2013	463,126		463,126	434,220[c]	May 2016	
	2014-2016[e]	12 Feb 2014	220,043		220,043[f]			1,071,609
r yron rote[b]	2012-2014	08 Mar 2012	414,468			310,596[c]	7 May 2015[d]	
	2013-2015	11 Feb 2013	142,278		142,278[f]	129,816[c]	May 2016	

[a] For awards under the 2012-2014, 2013-2015, 2014-2016 and 2015-2017 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 44.4%, which is conditional on the TSR, operating cash flow and each 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 7 May 2015 was £4.57 and for ADSs was $41.83. For the assumed vestings dated May 2016 a price of £3.72 per ordinary share and $33.81 per ADS has been used. These are the average prices from the fourth quarter of 2015.

[d]

The 2012-2014 award vested on 7 May 2015, which resulted in an increase in value at vesting of £297,110 for Iain Conn and $193,922 for Byron Grote. Details for Bob Dudley and Brian Gilvary can be found in the single figure table on page 77.

[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.

[f] 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)

ion type	At 1 Jan 2015	Granted	Exercised	At 31 Dec 2015	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
ve directors							
SAYE	2,005[a]		2,005		£3.68	£4.47	01 Jan 2015

The closing market prices of an ordinary share and of an ADS on 31 December 2015 were £3.54 and $31.26 respectively.

During 2015 the highest market prices were £4.84 and $43.60 respectively and the lowest market prices were £3.23 and $29.38 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] In accordance with the rules, potential maximum shares were pro-rated with a shorter exercise period and the option was exercised on 11 June 2015.

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Remuneration policy table

This is a summary of the remuneration policy as set out in the 2014 directors remuneration report and approved by shareholders.

Element and purpose	Operation and opportunity
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.	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 all employees in relevant countries are considered.
Annual bonus Provides a variable level of remuneration dependent on short-term performance against the annual plan.	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.

Deferred bonus Reinforces the long-term nature of the business and the importance of sustainability, linking a further part of remuneration to equity.	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.
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.	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.
Pension Recognizes competitive practice in home country.	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.	

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Performance framework		
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.	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.	
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.	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.	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.

	The principal measures of annual bonus will be based on value creation and may include financial measures such as operating cash	
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.	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.
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 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.	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

	The committee identifies the specific strategic imperatives to be included every year and may also alter the other measures if others are	basis of materially misstated financial or other data.
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.	Pension in the UK is not directly linked to performance. Pension in the US includes bonus in determining benefit level.	

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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 2015.

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 a contribution to an office and 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 2015.

2015 remuneration (audited)

£ thousand		Fees		Benefits[a]		Total
	2015	2014	2015	2014	2015	2014
Carl-Henric Svanberg	785	785	38	37	823	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 944%.

Chairman	Ordinary shares or equivalents at 1 Jan 2015	Ordinary shares or equivalents at 31 Dec 2015	Change from 31 Dec 2015 to 22 Feb 2016	Ordinary shares or equivalents total at 22 Feb 2016
Carl-Henric Svanberg	1,076,695	2,076,695		2,076,695

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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, geopolitical, 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] Committee chairmen do not receive an additional membership fee for the committee they chair.
[c] For members of the audit, geopolitical, Gulf of Mexico, SEEA and remuneration committees.

2015 remuneration (audited)

£ thousand	Fees		Benefits[a]		Total	
	2015	2014	2015	2014	2015	2014
Paul Anderson	177	175	28	48	205	223
Alan Boeckmann	178	70	14	17	192	87
Admiral Frank Bowman	177	165	12	17	189	182
Antony Burgmans	149	150	19	9	168	159
Cynthia Carroll	127	125	68	66	195	191
George David[b]	60	185	15	18	75	203
Ian Davis	145	150	3	5	148	155
Professor Dame Ann Dowling[c]	141	140	1	11	142	151
Brendan Nelson	125	125	11	16	136	141
Phuthuma Nhleko	167	150	11	9	178	159
Paula Rosput Reynolds[d]	93		56		149	
Sir John Sawers[d]	85		0		85	
Andrew Shilston	165	150	3	8	168	158

[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.
[b] Retired on 16 April 2015.
[c] In addition, Professor Dame Ann Dowling received £25,000 for chairing and being a member of the BP technology advisory council.

[d] Appointed on 14 May 2015.

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.

	Ordinary shares or equivalents at 1 Jan 2015	Ordinary shares or equivalents at 31 Dec 2015	Change from 31 Dec 2015 to 22 Feb 2016	Ordinary shares or equivalents total at 22 Feb 2016	Value of current shareholding	% of policy achieved
Paul Anderson	30,000[a]	30,000[a]		30,000[a]	$151,500	110
Alan Boeckmann	43,890[a]	44,772[a]		44,772[a]	$226,099	164
Admiral Frank Bowman	16,320[a]	24,864[a]		24,864[a]	$125,563	91
Antony Burgmans	10,156	10,156		10,156	£36,257	40
Cynthia Carroll	10,500[a]	10,500[a]		10,500[a]	$53,025	39
George David[b]	579,000[a]					
Ian Davis	22,420	23,854		23,854	£85,159	95
Professor Dame Ann Dowling	22,320	22,320		22,320	£79,682	89
Brendan Nelson	11,040	11,040		11,040	£39,413	44
Phuthuma Nhleko						0
Paula Rosput Reynolds[c]		52,200[a]		52,200[a]	$263,610	192
Sir John Sawers[c]		13,528		13,528	£48,295	54
Andrew Shilston	15,000	15,000		15,000	£53,550	45

[a] Held as ADSs.
[b] Retired on 16 April 2015.
[c] Appointed on 14 May 2015.

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 2015, 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 4 March 2016.

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Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

The board of directors and shareholders of BP p.l.c.

We have audited the accompanying group balance sheets of BP p.l.c. as of 31 December 2015 and 31 December 2014, 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 2015. 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 2015 and 31 December 2014, and the group results of its operations and its cash flows for each of the three years in the period ended 31 December 2015, 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.

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 2015, based on criteria established in the UK Financial Reporting Council s Guidance on Risk Management, Internal Control and Related Financial and Business Reporting and our report dated 4 March 2016 expressed an unqualified opinion.

/s/ Ernst & Young LLP

London, United Kingdom

4 March 2016

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Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

The board of directors and shareholders of BP p.l.c.

We have audited BP p.l.c. s internal control over financial reporting as of 31 December 2015, based on criteria established in the UK Financial Reporting Council s Guidance on Risk Management, Internal Control and Related Financial and Business Reporting. 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 244. 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 2015, based on the UK Financial Reporting Council s 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 2015 and 2014, 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 2015, and our report dated 4 March 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

London, United Kingdom

4 March 2016

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 4 March 2016, 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 2015 in the following Registration Statements:

Registration Statement on Form F-3 (File Nos. 333-208478 and 333-208478-01) of BP Capital Markets p.l.c. and BP p.l.c.; and Registration Statements on Form S-8 (File Nos. 333-67206, 333-79399, 333-103924, 333-123482, 333-123483, 333-131583, 333-131584, 333-132619, 333-146868, 333-146870, 333-146873, 333-173136, 333-177423, 333-179406, 333-186462, 333-186463, 333-199015, 333-200794, 333-200795, 333-207188 and 333-207189) of BP p.l.c.

/s/ Ernst & Young LLP

London, United Kingdom

4 March 2016

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Group income statement

For the year ended 31 December				$ million
	Note	**2015**	2014	2013
Sales and other operating revenues	5	**222,894**	353,568	379,136
Earnings from joint ventures after interest and tax	15	**(28)**	570	447
Earnings from associates after interest and tax	16	**1,839**	2,802	2,742
Interest and other income	6	**611**	843	777
Gains on sale of businesses and fixed assets	4	**666**	895	13,115
Total revenues and other income		**225,982**	358,678	396,217
Purchases	18	**164,790**	281,907	298,351
Production and manufacturing expenses[a]		**37,040**	27,375	27,527
Production and similar taxes	5	**1,036**	2,958	7,047
Depreciation, depletion and amortization	5	**15,219**	15,163	13,510
Impairment and losses on sale of businesses and fixed assets	4	**1,909**	8,965	1,961
Exploration expense	7	**2,353**	3,632	3,441
Distribution and administration expenses		**11,553**	12,266	12,611
Profit (loss) before interest and taxation		**(7,918)**	6,412	31,769
Finance costs[a]	6	**1,347**	1,148	1,068
Net finance expense relating to pensions and other post-retirement benefits	23	**306**	314	480
Profit (loss) before taxation		**(9,571)**	4,950	30,221
Taxation[a]	8	**(3,171)**	947	6,463
Profit (loss) for the year		**(6,400)**	4,003	23,758
Attributable to				
BP shareholders		**(6,482)**	3,780	23,451
Non-controlling interests		**82**	223	307
		(6,400)	4,003	23,758
Earnings per share cents				
Profit (loss) for the year attributable to BP shareholders				
Basic	10	**(35.39)**	20.55	123.87
Diluted	10	**(35.39)**	20.42	123.12

[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	Note	2015	2014	$ million 2013
Profit (loss) for the year		**(6,400)**	4,003	23,758
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**(4,119)**	(6,838)	(1,608)
Exchange gains (losses) on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**23**	51	22
Available-for-sale investments marked to market		**1**	(1)	(172)
Available-for-sale investments reclassified to the income statement			1	(523)
Cash flow hedges marked to market	29	**(178)**	(155)	(2,000)
Cash flow hedges reclassified to the income statement	29	**249**	(73)	4
Cash flow hedges reclassified to the balance sheet	29	**22**	(11)	17
Share of items relating to equity-accounted entities, net of tax		**(814)**	(2,584)	(24)
Income tax relating to items that may be reclassified	8	**257**	147	147
		(4,559)	(9,463)	(4,137)
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	23	**4,139**	(4,590)	4,764
Share of items relating to equity-accounted entities, net of tax		**(1)**	4	2
Income tax relating to items that will not be reclassified	8	**(1,397)**	1,334	(1,521)
		2,741	(3,252)	3,245
Other comprehensive income		**(1,818)**	(12,715)	(892)
Total comprehensive income		**(8,218)**	(8,712)	22,866
Attributable to				
BP shareholders		**(8,259)**	(8,903)	22,574
Non-controlling interests		**41**	191	292
		(8,218)	(8,712)	22,866

[a] See Note 31 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 2015	**43,902**	**(20,719)**	**(3,409)**	**(897)**	**92,564**	**111,441**	**1,201**	**112,642**
Profit (loss) for the year					**(6,482)**	**(6,482)**	**82**	**(6,400)**

Other comprehensive income			**(3,858)**	**74**	**2,007**	**(1,777)**	**(41)**	**(1,818)**
Total comprehensive income			**(3,858)**	**74**	**(4,475)**	**(8,259)**	**41**	**(8,218)**
Dividends[b]					**(6,659)**	**(6,659)**	**(91)**	**(6,750)**
Share-based payments, net of tax		**755**			**(99)**	**656**		**656**
Share of equity-accounted entities changes in equity, net of tax					**40**	**40**		**40**
Transactions involving non-controlling interests					**(3)**	**(3)**	**20**	**17**
At 31 December 2015	**43,902**	**(19,964)**	**(7,267)**	**(823)**	**81,368**	**97,216**	**1,171**	**98,387**
At 1 January 2014	43,656	(20,971)	3,525	(695)	103,787	129,302	1,105	130,407
Profit (loss) 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[b]					(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 (loss) 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[b]					(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

[a] See Note 31 for further information.
[b] See Note 9 for further information.

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Group balance sheet

At 31 December			$ million
	Note	**2015**	2014
Non-current assets			
Property, plant and equipment	11	**129,758**	130,692
Goodwill	13	**11,627**	11,868
Intangible assets	14	**18,660**	20,907
Investments in joint ventures	15	**8,412**	8,753
Investments in associates	16	**9,422**	10,403
Other investments	17	**1,002**	1,228
Fixed assets		**178,881**	183,851
Loans		**529**	659
Trade and other receivables	19	**2,216**	4,787
Derivative financial instruments	29	**4,409**	4,442
Prepayments		**1,003**	964
Deferred tax assets	8	**1,545**	2,309
Defined benefit pension plan surpluses	23	**2,647**	31
		191,230	197,043
Current assets			
Loans		**272**	333
Inventories	18	**14,142**	18,373
Trade and other receivables	19	**22,323**	31,038
Derivative financial instruments	29	**4,242**	5,165
Prepayments		**1,838**	1,424
Current tax receivable		**599**	837
Other investments	17	**219**	329
Cash and cash equivalents	24	**26,389**	29,763
		70,024	87,262
Assets classified as held for sale	3	**578**	
		70,602	87,262
Total assets		**261,832**	284,305
Current liabilities			
Trade and other payables	21	**31,949**	40,118
Derivative financial instruments	29	**3,239**	3,689
Accruals		**6,261**	7,102
Finance debt	25	**6,944**	6,877
Current tax payable		**1,080**	2,011
Provisions	22	**5,154**	3,818
		54,627	63,615
Liabilities directly associated with assets classified as held for sale	3	**97**	
		54,724	63,615
Non-current liabilities			
Other payables	21	**2,910**	3,587
Derivative financial instruments	29	**4,283**	3,199
Accruals		**890**	861

Finance debt	25	**46,224**	45,977
Deferred tax liabilities	8	**9,599**	13,893
Provisions	22	**35,960**	29,080
Defined benefit pension plan and other post-retirement benefit plan deficits	23	**8,855**	11,451
		108,721	108,048
Total liabilities		**163,445**	171,663
Net assets		**98,387**	112,642
Equity			
BP shareholders equity	31	**97,216**	111,441
Non-controlling interests	31	**1,171**	1,201
Total equity	31	**98,387**	112,642

C-H Svanberg Chairman

R W Dudley Group Chief Executive

4 March 2016

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Group cash flow statement

For the year ended 31 December $ million

	Note	2015	2014	2013
Operating activities				
Profit (loss) before taxation		**(9,571)**	4,950	30,221
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities				
Exploration expenditure written off	7	**1,829**	3,029	2,710
Depreciation, depletion and amortization	5	**15,219**	15,163	13,510
Impairment and (gain) loss on sale of businesses and fixed assets	4	**1,243**	8,070	(11,154)
Earnings from joint ventures and associates		**(1,811)**	(3,372)	(3,189)
Dividends received from joint ventures and associates		**1,614**	1,911	1,391
Interest receivable		**(247)**	(276)	(314)
Interest received		**176**	81	173
Finance costs	6	**1,347**	1,148	1,068
Interest paid		**(1,080)**	(937)	(1,084)
Net finance expense relating to pensions and other post-retirement benefits	23	**306**	314	480
Share-based payments		**321**	379	297
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	23	**(592)**	(963)	(920)
Net charge for provisions, less payments		**11,792**	1,119	1,061
(Increase) decrease in inventories		**3,375**	10,169	(1,193)
(Increase) decrease in other current and non-current assets		**6,796**	3,566	(2,718)
Increase (decrease) in other current and non-current liabilities		**(9,328)**	(6,810)	(2,932)
Income taxes paid		**(2,256)**	(4,787)	(6,307)
Net cash provided by operating activities		**19,133**	32,754	21,100
Investing activities				
Capital expenditure		**(18,648)**	(22,546)	(24,520)
Acquisitions, net of cash acquired		**23**	(131)	(67)
Investment in joint ventures		**(265)**	(179)	(451)
Investment in associates		**(1,312)**	(336)	(4,994)
Proceeds from disposals of fixed assets	4	**1,066**	1,820	18,115
Proceeds from disposals of businesses, net of cash disposed	4	**1,726**	1,671	3,884
Proceeds from loan repayments		**110**	127	178
Net cash used in investing activities		**(17,300)**	(19,574)	(7,855)
Financing activities				
Net issue (repurchase) of shares			(4,589)	(5,358)
Proceeds from long-term financing		**8,173**	12,394	8,814
Repayments of long-term financing		**(6,426)**	(6,282)	(5,959)
Net increase (decrease) in short-term debt		**473**	(693)	(2,019)
Net increase (decrease) in non-controlling interests		**(5)**	9	32
Dividends paid				
BP shareholders	9	**(6,659)**	(5,850)	(5,441)

Non-controlling interests	**(91)**	(255)	(469)
Net cash used in financing activities	**(4,535)**	(5,266)	(10,400)
Currency translation differences relating to cash and cash equivalents	**(672)**	(671)	40
Increase (decrease) in cash and cash equivalents	**(3,374)**	7,243	2,885
Cash and cash equivalents at beginning of year	**29,763**	22,520	19,635
Cash and cash equivalents at end of year	**26,389**	29,763	22,520

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 2015 were approved and signed by the group chief executive and chairman on 4 March 2016 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. 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 on a going concern basis and in accordance with IFRS and IFRS Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2015. 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, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. 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 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

Goodwill

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.

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 2015. 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 a member of the board of directors of

1. Significant accounting policies, judgements, estimates and assumptions   continued

Rosneft since 2013 and he is a member of the Rosneft board s Strategic Planning Committee. During 2015, a second BP-nominated director, Guillermo Quintero, was elected to the Rosneft board. BP also 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.

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 group chief executive, BP s 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 5.

Foreign currency translation

In individual subsidiaries, joint ventures and associates, transactions in foreign currencies are initially recorded in the functional currency of those entities at the spot exchange rate on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the spot exchange rate on 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, associates, and related goodwill, are translated into US dollars at the spot exchange rate on 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, and actions required to complete the plan of sale should indicate that it is unlikely that significant changes to the plan will be made or that the plan will be withdrawn.

Property, plant and equipment and intangible assets are not depreciated or amortized once classified as held for sale.

Intangible assets

Intangible assets, other than goodwill, include expenditure on the exploration for and evaluation of oil and natural gas resources, computer software, patents, licences and trademarks and are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses.

Intangible assets acquired separately from a business are carried initially at cost. 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, other than capitalized exploration and appraisal costs as described below, are amortized on a straight-line basis over their expected useful lives. For patents, licences and trademarks, expected useful life is the shorter of the duration of the legal agreement and economic useful life, and can range from three to 15 years. Computer software costs generally have a useful life of three to five years.

1. Significant accounting policies, judgements, estimates and assumptions continued

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 as described below.

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 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 recognized as an expense 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 costs are 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. If it is determined that development will not occur then the costs are expensed.

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 of 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 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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

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 169, which is unaudited. Details on BP s proved reserves and production compliance and governance processes are provided on page 228.

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 changes in depreciation expense or an immediate write-down of the property s carrying value.

The 2015 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 169. 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 11 and Note 5 respectively.

Impairment of property, plant and equipment, intangible assets, and goodwill

The group assesses assets or groups of assets, called cash-generating units (CGUs), for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or CGU may not be recoverable; for example, changes in the group s business plans, changes in the group s assumptions about commodity prices, 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 or CGU s recoverable amount. Individual assets are grouped into CGUs 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. A CGU s recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU 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 assumptions regarding market conditions, such as oil prices, natural gas prices, refining margins, refined product margins and cost inflation rates are set by senior management. These 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 group 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 the lower of its recoverable amount and the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Impairment reversals are recognized in profit or loss. After 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.

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 to which goodwill has been allocated is compared with its recoverable amount. Where the recoverable amount of the group of CGUs is less than the carrying amount (including goodwill), an impairment loss is recognized. An impairment loss recognized for goodwill is not reversed in a subsequent period.

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1. Significant accounting policies, judgements, estimates and assumptions continued

Significant estimate or judgement: recoverability of asset carrying values

Determination as to whether, and by how much, an asset, CGU, 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 production and reserves volumes. Judgement is also required when determining the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment testing purposes.

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 the asset, CGU or group of CGUs containing goodwill and the test is performed on a post-tax basis. The post-tax discount rate used is based upon the cost of funding the group derived from an established model. Adjustments are made, where applicable, to take into account any specific risks relating to the country where the cash-generating unit is located. In 2015 the discount rate used to determine recoverable amounts based on fair value less costs of disposal was 7% (2014 8%), with a 2% premium added in higher-risk countries.

When estimating the fair value of our Upstream assets, assumptions reflect 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 price assumptions used in such tests are $90 per barrel for Brent in 2021 (2014 $97 per barrel in 2020) and $5.60/mmBtu for Henry Hub in 2021 (2014 $6.00/mmBtu in 2020), both inflated at a rate of 2% per annum for the remaining life of the asset (2014 2.5%). These long-term assumptions are derived from the $80 per barrel real oil price and $5/mmBtu real Henry Hub assumptions 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 performed at the year end are shown in the table below:

Price assumptions for the first five years	**as at 31 December**

					2015
	2016	**2017**	**2018**	**2019**	**2020**
Brent oil price ($/bbl)	**40**	**47**	**52**	**54**	**56**
Henry Hub natural gas price ($/mmBtu)	**2.38**	**2.76**	**2.90**	**3.03**	**3.18**

					as at 31 December 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

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 pre-tax discount rate is derived from the cost of funding the group calculated using an established model, and is adjusted, where applicable, to take into account any specific risks relating to the country where the cash-generating unit is located. In 2015 the discount rate used to determine recoverable amounts based on value in use was 11% (2014 12%), 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 restricted to proved and probable reserves.

For value-in-use calculations relating to Upstream assets, 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 2015, the group s long-term flat nominal price assumptions were $90 per barrel for Brent and $6.50/mmBtu for Henry Hub (2014 $90 per barrel and $6.50/mmBtu). These long-term price assumptions are subject to periodic review.

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 $11.6 billion on its balance sheet (2014 $11.9 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, 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 and reversals recognized in the income statement are provided in Note 4 and details on the carrying amounts of assets are shown in Note 11, Note 13 and Note 14.

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 the lower of cost on a weighted average basis and net realizable value.

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

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1. Significant accounting policies, judgements, estimates and assumptions continued

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 on a straight-line basis over the lease term.

Financial assets

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 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

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, interest recognized using the effective interest method, 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 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 28 for information on overdue receivables.

Financial liabilities

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, net of transaction costs. 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 in interest and other income and finance costs respectively.

This category of financial liabilities includes trade and other payables and finance debt, except finance debt designated in a fair value hedge relationship.

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 recognized initially at fair value on the date on which a derivative contract is entered into and 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 (for example, oil, oil products, gas or power) that can be settled net in cash, 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 gain 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 subsequent to the initial valuation are recognized immediately through the income statement.

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1. Significant accounting policies, judgements, estimates and assumptions continued

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 and certain currency risks 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. See Note 16, Note 28 and Note 29 for further information.

Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The group categorizes assets and liabilities measured at fair value into one of three levels depending on the ability to observe inputs employed in their measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are inputs that are observable, either directly or indirectly, other than quoted prices included within level 1 for the asset or liability. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or BP s assumptions about pricing by market participants.

Significant estimate or judgement: 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. 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 available active market pricing data and modelled using the maximum available external pricing information. Additionally, where limited data exists for certain products, prices are determined using historic and long-term pricing relationships. Price volatility is also an input for options models.

Changes in the key assumptions could have a material impact on the fair value gains and losses on derivatives recognized in the income statement. For more information see Note 29.

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% (2014 2.75%) or a real discount rate of 0.75% (2014 0.75%), 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).

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1. Significant accounting policies, judgements, estimates and assumptions continued

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.

During 2015, BP signed agreements in principle, which were subject to execution of definitive agreements, to settle all federal and state claims and claims made by more than 400 local government entities. Further detail is provided in Note 2. Certain agreements are subject to approval by the court of a Consent Decree. A provision for amounts payable under these agreements has, therefore, been recognized. The agreements significantly reduce the uncertainties faced by BP following the Gulf of Mexico oil spill in 2010. However, there continues to be uncertainty regarding the outcome or resolution of current or future litigation and the extent and timing of costs relating to the incident not covered by these agreements.

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, are disclosed as contingent liabilities, and are described in Note 2. Contingent liabilities are disclosed in relation to business economic loss (BEL) claims under the Plaintiffs Steering Committee (PSC) settlement, securities-related litigation, other litigation, including claims from parties excluded from or who opted out of the PSC settlement, and under the settlement agreements with Anadarko and MOEX and other agreements.

Management believes that no reliable estimate can currently be made of any BEL claims not yet processed or processed but not yet paid, except where an eligibility notice has been issued and is not subject to appeal by BP within the claims facility. The submission deadline for BEL claims passed on 8 June 2015; no further claims can be submitted. A significant number of BEL claims have been received but have not yet been processed and it is not possible to quantify the total value of the claims. A revised policy for the matching of revenue and expenses for BEL claims was introduced in May 2014 and, of the claims assessable under the new policy, the majority have not yet been determined at this time. For this and other reasons set out in Note 2, we are unable to reliably estimate future trends of the number and proportion of claims that will be determined to be eligible, nor can we reliably estimate the value of such claims. A provision for such BEL claims will be established when these uncertainties are sufficiently reduced and a reliable estimate can be made of the liability.

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 17 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. 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. 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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

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 2015 was a real rate of 0.75% (2014 0.75%), 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 22. As further described in Note 32, the group is subject to claims and actions. The facts and circumstances relating to particular cases are evaluated regularly in determining whether a provision relating to a specific litigation should be recognized 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.

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 recognized in the balance sheet for each plan comprises the difference between the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds) and 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, typically by way of refund.

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 23.

1. Significant accounting policies, judgements, estimates and assumptions continued

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 23.

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 23.

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 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
- 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
- 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 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.

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 8.

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:

- Customs duties or sales taxes incurred on the purchase of goods and services which are not recoverable from the taxation authority are 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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

Own equity instruments Treasury shares

The group s holdings in its own equity instruments are shown as deductions from shareholders equity at cost. 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. 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.

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.

IFRS 9 Financial Instruments 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.

IFRS 15 Revenue from Contracts with Customers 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 2018. IFRS 15 will supersede IAS 18 Revenue .

The IASB has issued IFRS 16 Leases which provides a new model for lease accounting in which all leases, other than short-term and small-ticket-item leases, will be accounted for by the recognition on the balance sheet of a right-to-use asset and a lease liability, and the subsequent amortization of the right-to-use asset over the lease term. IFRS 16 will be effective for annual periods beginning on or after 1 January 2019 and is expected to have a significant effect on the group s financial statements, significantly increasing the group s recognized assets and liabilities and potentially affecting the presentation and timing of recognition of charges in the income statement. Information on the group s leases currently classified as operating leases, which are not recognized on the balance sheet, is provided in Note 27.

BP does not expect to adopt IFRS 9 or IFRS 15 before 1 January 2018 and has not yet determined its date of adoption for IFRS 16. The group has not yet completed its evaluation of the effect of adoption of these standards. The EU has not yet adopted IFRS 9, IFRS 15 or IFRS 16.

There are no other standards and interpretations in issue but not yet adopted that the directors anticipate will have a material effect on the reported income or net assets of the group.

2. Significant event Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill 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 $55.5 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 business economic loss claims under the Plaintiffs Steering Committee (PSC) settlement, see *Provisions and contingent liabilities* below.

On 2 July 2015, agreements in principle to settle all federal and state claims and claims made by more than 400 local government entities were signed. These agreements in principle were subject to execution of definitive agreements, including a Consent Decree with the United States and Gulf states with respect to the Clean Water Act penalty and natural resource damages and other claims, a Settlement Agreement with five Gulf states with respect to state claims for economic loss, property damage and other claims, and resolution to BP s satisfaction of the economic loss, property damage and other claims with more than 400 local government entities. The proposed Consent Decree between the United States, the Gulf states and BP was available for public comment until early December 2015 and is subject to final court approval. The Consent Decree and Settlement Agreement with the five Gulf states are conditional upon each other and neither will become effective unless there is final court approval of the Consent Decree. The United States is expected to file a motion with the court to enter the Consent Decree as a final settlement around the end of

March, which the court will then consider. During 2015, the Settlement Agreement with the five Gulf states was executed. BP has accepted releases received from the vast majority of local government entities and payments required under those releases were made during 2015. For more information on the proposed Consent Decree and Settlement Agreement see Legal proceedings on page 238.

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2. Significant event Gulf of Mexico oil spill continued

The agreements described above (the Agreements) significantly reduce the uncertainties faced by BP following the Gulf of Mexico oil spill in 2010. There continues to be uncertainty regarding the outcome or resolution of current or future litigation and the extent and timing of costs relating to the incident not covered by the Agreements. The total amounts that will ultimately be paid by BP in relation to the incident 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 uncertainties could have a material impact on our consolidated financial position, results and cash flows.

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
	2015	2014	2013
Income statement			
Production and manufacturing expenses	**11,709**	781	430
Profit (loss) before interest and taxation	**(11,709)**	(781)	(430)
Finance costs	**247**	38	39
Profit (loss) before taxation	**(11,956)**	(819)	(469)
Less: Taxation	**3,492**	262	73
Profit (loss) for the period	**(8,464)**	(557)	(396)
Balance sheet			
Current assets			
Trade and other receivables	**686**	1,154	
Current liabilities			
Trade and other payables	**(693)**	(655)	
Accruals	**(40)**		
Provisions	**(3,076)**	(1,702)	
Net current assets (liabilities)	**(3,123)**	(1,203)	
Non-current assets			
Other receivables		2,701	
Non-current liabilities			
Other payables	**(2,057)**	(2,412)	
Accruals	**(186)**	(169)	
Provisions	**(13,431)**	(6,903)	
Deferred tax	**5,200**	1,723	
Net non-current assets (liabilities)	**(10,474)**	(5,060)	
Net assets (liabilities)	**(13,597)**	(6,263)	
Cash flow statement			
Profit (loss) before taxation	**(11,956)**	(819)	(469)
Finance costs	**247**	38	39
Net charge for provisions, less payments	**11,296**	939	1,129
(Increase) decrease in other current and non-current assets		(662)	(1,481)

Increase (decrease) in other current and non-current liabilities	**(732)**	(792)	(618)
Pre-tax cash flows	**(1,145)**	(1,296)	(1,400)

The impact on net cash provided by operating activities, on a post-tax basis, amounted to an outflow of $1,130 million (2014 outflow of $9 million and 2013 outflow of $73 million).

Trust fund

BP established the Deepwater Horizon Oil Spill Trust (the Trust), 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. 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. We use the term reimbursement asset to describe this asset. BP does not actually receive any reimbursements from the trust fund, instead payments are made directly from the trust fund, and BP is released from its corresponding obligation. This is the portion of the estimated future expenditure provided for that will be settled by payments from the trust fund. During 2014, cumulative charges to be paid by the Trust reached $20 billion. Subsequent additional costs, over and above those provided within the $20 billion, are expensed to the income statement as incurred.

At 31 December 2015, $686 million of the provisions and payables are eligible to be paid from the Trust. The reimbursement asset is recorded within Trade and other receivables on the balance sheet, all of which is classified as current, as payment of all amounts covered by the remaining reimbursement asset may be requested during 2016. During 2015, $3,022 million of provisions and $147 million of payables were paid from the Trust.

At 31 December 2015, the remaining cash in the Trust not allocated for specific purposes was $25 million. This unallocated amount was exhausted in January 2016 and BP commenced paying claims and other costs not covered by the specific-purpose cash balances. The total cash remaining in the Trust and associated qualifying settlement funds, amounting to $1.4 billion, includes $0.7 billion in the seafood compensation fund, $0.2 billion held for natural resource damage early restoration projects and $0.5 billion held in relation to certain other specified costs under the PSC settlement.

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2. Significant event Gulf of Mexico oil spill continued

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. At 31 December 2015, $2,432 million remains in Other payables in relation to this agreement, of which $530 million falls due in 2016. In addition, Other payables at 31 December 2015 includes the remaining $219 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.

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 2015
	Environmental	Litigation and claims	Clean Water Act	Total
At 1 January	1,141	3,954	3,510	8,605
Increase in provision	5,393	5,832	661	11,886
Unwinding of discount	94	50	68	212
Change in discount rate	(149)	(74)	(110)	(333)
Reclassified to other payables	(459)	(125)		(584)
Utilization paid by BP	(23)	(234)		(257)
paid by the trust fund	(78)	(2,944)		(3,022)
At 31 December	5,919	6,459	4,129	16,507
Of which current	227	2,849		3,076
non-current	5,692	3,610	4,129	13,431

				$ million Cumulative since the incident
	Environmental	Litigation and claims	Clean Water Act	Total
Net increase in provision	19,992	32,427	4,171	56,590
Unwinding of discount	107	56	68	231
Change in discount rate	(130)	(74)	(110)	(314)

Reclassified to other payables	(459)	(4,408)		(4,867)
Utilization paid by BP	(11,710)	(4,314)		(16,024)
paid by the trust fund	(1,881)	(17,228)		(19,109)
At 31 December 2015	5,919	6,459	4,129	16,507

Environmental

The environmental provision at 31 December 2015 includes amounts payable for natural resource damage costs under the proposed Consent Decree. These amounts are payable in instalments over 16 years commencing one year after the court approves the Consent Decree; the majority of the unpaid balance of this natural resource damages settlement accrues interest at a fixed rate. During 2011, BP entered into a framework agreement with natural resource trustees for the United States and five Gulf states, providing for $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. Remaining amounts payable under this framework agreement, that are not yet allocated to specific projects, are also included in environmental provisions.

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 amounts provided under the Agreements in relation to state claims that have not yet been paid. Claims administration costs and legal costs have also been provided for.

Litigation and claims PSC settlement

The Economic and Property Damages Settlement Agreement (EPD Settlement Agreement) with the PSC provides for a court-supervised settlement programme, the Deepwater Horizon Court Supervised Settlement Program (DHCSSP), which commenced operation on 4 June 2012. 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 239. 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.

Management believes that no reliable estimate can currently be made of any business economic loss claims 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 submission deadline for business economic loss claims passed on 8 June 2015; no further claims may be submitted. A significant number of business economic loss claims have been received but have not yet been processed and it is not possible to quantify the total value of the claims.

A revised policy for the matching of revenue and expenses for business economic loss claims was introduced in May 2014 and, of the claims assessable under the revised policy, the majority have not yet been determined at this time. Uncertainties regarding the proper application of the revised policy to particular claims and categories of claims continue to arise as the claims administrator has applied the revised policy. Only a small proportion of claim determinations have been made under some of the specialized frameworks that have been put in place for particular industries, namely construction, agriculture, professional services and education, and so determinations to date may not be representative of the total population

2. Significant event Gulf of Mexico oil spill continued

of claims. In addition, although some pre-determination data has been provided to BP, detailed data on the majority of pre-determination claims is not available due to a court order to protect claimant confidentiality. Therefore, there is an insufficient level of detail to enable a complete or clear understanding of the composition of the underlying claims population.

There is insufficient data available 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 are unable to reliably estimate future trends of the number and proportion of claims that will be determined to be eligible, nor can we reliably estimate the value of such claims. A provision for such business economic loss claims will be established when these uncertainties are sufficiently reduced 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, including amounts already paid, is $12.4 billion. Prior to the end of the month following the balance sheet date, the DHCSSP had issued eligibility notices, many of which are disputed by BP, in respect of business economic loss claims of approximately $402 million which have not been provided for. The total cost of the PSC settlement is likely to be significantly higher than the amount recognized to date of $12.4 billion because the current estimate does not reflect business economic loss claims 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.

There continues to be a high level of uncertainty with regards to the amounts that ultimately will be paid in relation to current claims as described above and there is also uncertainty as to the cost of administering the claims process under the DHCSSP and in relation to future legal costs. The timing of payment of provisions related to the PSC settlement is dependent upon ongoing claims facility activity and is therefore also uncertain.

Litigation and claims Other claims

The provision recognized for litigation and claims includes amounts agreed under the Agreements in relation to state claims. The amount provided in respect of state claims is payable over 18 years from the date the court approves the Consent Decree, of which $1 billion is due following the court approval of the Consent Decree. The vast majority of local government entities who filed claims have issued releases, which were accepted by BP; amounts due under those releases were paid during 2015.

Clean Water Act penalties

A provision has been recognized for penalties under Section 311 of the Clean Water Act, as determined in the Agreements. The amount is payable in instalments over 15 years, commencing one year after the court approves the Consent Decree. The unpaid balance of this penalty accrues interest at a fixed rate.

Provision movements

The total amount recognized as an increase in provisions during the year was $11,886 million. This increase relates primarily to amounts provided for the Agreements, and additional increases in the litigation and claims provision for business economic loss claims, associated claims administration costs and other items. After deducting amounts utilized during the year totalling $3,279 million, comprising payments from the trust fund of $3,022 million and payments made directly by BP of $257 million (2014 $2,071 million, comprising payments from the trust fund of $1,681 million and payments made directly by BP of $390 million), and after adjustments for discounting, the remaining provision as at 31 December 2015 was $16,507 million (2014 $8,605 million).

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 2015.

Business economic loss claims under the PSC settlement

The potential cost of business economic loss claims not yet 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. See *Provisions* above for further information.

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 July 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 2015. 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 2015.

Other litigation

In addition to the securities class actions described above, BP is named as a defendant in approximately 2,700 other civil lawsuits brought by individuals and corporations 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 may still be brought. Among other claims, these lawsuits assert claims for personal injury 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 the Oil Pollution Act of 1990 (OPA 90) in relation to the 2010 federal deepwater drilling moratoria. Furthermore, there are also uncertainties around the outcomes of any further litigation including by parties excluded from, or parties who opted out of, the PSC settlement. 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 is it possible to determine the timing of any payment that may arise. Therefore no amounts have been provided for these items as at 31 December 2015.

Settlement and other agreements

Under the settlement agreements with Anadarko and MOEX, the other working interest owners in the Macondo well at the time of the incident, 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 2015. There are also agreements indemnifying certain third-party contractors in relation to litigation costs and certain other claims. A contingent liability also exists in relation to other obligations under these agreements.

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2. Significant event Gulf of Mexico oil spill continued

The magnitude and timing of all possible obligations in relation to the Gulf of Mexico oil spill continue to be subject to a high degree of uncertainty. Any such possible obligations are therefore contingent liabilities and, at present, it is not practicable to estimate their magnitude or possible timing of payment. Furthermore, other material unanticipated obligations may arise in future in relation to the incident.

Impact upon the group income statement

The amount of the provision recognized during the year can be reconciled to the charge to the income statement as follows:

$ million

	2015	2014	2013	Cumulative since the incident
Net increase in provision	**11,886**	1,327	1,860	56,591
Change in discount rate relating to provisions	**(333)**	2	(5)	(314)
Costs charged directly to the income statement	**156**	114	136	4,514
Trust fund liability discounted				19,580
Change in discounting relating to trust fund liability				283
Recognition of reimbursement asset, net		(662)	(1,542)	(20,000)
Settlements credited to the income statement			(19)	(5,681)
(Profit) loss before interest and taxation	**11,709**	781	430	54,973
Finance costs	**247**	38	39	478
(Profit) loss before taxation	**11,956**	819	469	55,451

The group income statement for 2015 includes a pre-tax charge of $11,956 million (2014 pre-tax charge of $819 million) in relation to the Gulf of Mexico oil spill. The costs charged within production and manufacturing expenses in 2015 include $9.4 billion for the amounts provided under the Agreements, as well as the ongoing costs of operating the Gulf Coast Restoration Organization (GCRO), business economic loss claims, claims administration costs, legal and litigation costs. Finance costs of $247 million (2014 $38 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, amounts charged for the Agreements, 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

	2015	2014	2013	Cumulative since the incident
Trust fund liability discounted				19,580

Change in discounting relating to trust fund liability				283
Recognition of reimbursement asset		(662)	(1,542)	(20,000)
Other				8
Total (credit) charge relating to the trust fund		(662)	(1,542)	(129)
Environmental amount provided	**5,393**	190	47	8,527
change in discount rate relating to provisions	**(149)**	2	(5)	(130)
costs charged directly to the income statement	**59**			129
Total charge relating to environmental	**5,303**	192	42	8,526
Spill response amount provided			(113)	11,465
costs charged directly to the income statement				2,839
Total (credit) charge relating to spill response			(113)	14,304
Litigation and claims amount provided, net of provision derecognized	**5,832**	1,137	1,926	32,428
change in discount rate relating to provisions	**(74)**			(74)
costs charged directly to the income statement				184
Total charge relating to litigation and claims	**5,758**	1,137	1,926	32,538
Clean Water Act penalties amount provided	**661**			4,171
change in discount rate relating to provisions	**(110)**			(110)
Total charge relating to Clean Water Act penalties	**551**			4,061
Other costs charged directly to the income statement	**97**	114	136	1,354
Settlements credited to the income statement			(19)	(5,681)
(Profit) loss before interest and taxation	**11,709**	781	430	54,973
Finance costs	**247**	38	39	478
(Profit) loss before taxation	**11,956**	819	469	55,451

The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident remains subject to uncertainty as described under *Provisions and contingent liabilities* above.

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3. Non-current assets held for sale

On 15 January 2016 BP and Rosneft announced that they had signed a binding agreement to dissolve the German refining joint operation Ruhr Oel GmbH (ROG). The restructuring, which is expected to be completed in 2016, will result in the transfer of BP s interests, currently held via ROG, in the Bayernoil, MiRO Karlsruhe and PCK Schwedt refineries to Rosneft. In exchange, BP will take sole ownership of the Gelsenkirchen refinery and the solvent production facility DHC Solvent Chemie, both of which are also currently owned by ROG.

The major classes of assets and liabilities relating to BP s share of ROG s interests in the Bayernoil, MiRO Karlsruhe and PCK Schwedt refineries classified as held for sale at 31 December 2015 were:

	$ million
	2015
Assets	
Property, plant and equipment	**360**
Intangible assets	**3**
Inventories	**215**
Assets classified as held for sale	**578**
Liabilities	
Defined benefit pension plan and other post-retirement benefit plan deficits	**(97)**
Liabilities directly associated with assets classified as held for sale	**(97)**

The assets classified as held for sale are reported in the Downstream segment. The associated pension liabilities are reported in Other businesses and corporate.

There were no assets or liabilities classified as held for sale as at 31 December 2014.

4. Disposals and impairment

The following amounts were recognized in the income statement in respect of disposals and impairments.

			$ million
	2015	2014	2013
Gains on sale of businesses and fixed assets			
Upstream	**324**	405	371
Downstream	**316**	474	214
TNK-BP			12,500
Other businesses and corporate	**26**	16	30
	666	895	13,115

			$ million
	2015	2014	2013
Losses on sale of businesses and fixed assets			

Upstream	**124**	345	144
Downstream	**98**	401	78
Other businesses and corporate	**41**	3	8
	263	749	230
Impairment losses			
Upstream	**2,484**	6,737	1,255
Downstream	**265**	1,264	484
Other businesses and corporate	**155**	317	218
	2,904	8,318	1,957
Impairment reversals			
Upstream	**(1,080)**	(102)	(226)
Downstream	**(178)**		
	(1,258)	(102)	(226)
Impairment and losses on sale of businesses and fixed assets	**1,909**	8,965	1,961

Disposals

Disposal proceeds and principal gains and losses on disposals by segment are described below.

			$ million
	2015	2014	2013
Proceeds from disposals of fixed assets	**1,066**	1,820	18,115
Proceeds from disposals of businesses, net of cash disposed	**1,726**	1,671	3,884
	2,792	3,491	21,999
By business			
Upstream	**769**	2,533	1,288
Downstream	**1,747**	864	3,991
TNK-BP			16,646
Other businesses and corporate	**276**	94	74
	2,792	3,491	21,999

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4. Disposals and impairment continued

At 31 December 2015, deferred consideration relating to disposals amounted to $41 million receivable within one year (2014 $1,137 million and 2013 $23 million) and $385 million receivable after one year (2014 $333 million and 2013 $1,374 million). In addition, contingent consideration receivable relating to disposals amounted to $292 million at 31 December 2015 (2014 $454 million and 2013 $953 million), see Note 29 for further information.

Upstream

In 2015, gains principally resulted from the sale of our interests in the Central Area Transmission System in the North Sea, and from adjustments to prior year disposals in Canada.

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.

Downstream

In 2015, gains principally resulted from the disposal of our investment in the UTA European fuel cards business and our Australian bitumen business.

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.

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.

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 transactions categorized as business disposals in 2015 were the sales of our interests in the Central Area Transmission System in the North Sea and in the UTA European fuel cards business. 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. 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

	2015	2014	2013
Non-current assets	**154**	1,452	2,124
Current assets	**80**	182	2,371
Non-current liabilities	**(70)**	(395)	(94)
Current liabilities	**(50)**	(65)	(62)
Total carrying amount of net assets disposed	**114**	1,174	4,339
Recycling of foreign exchange on disposal	**16**	(7)	23
Costs on disposal[a]	**8**	128	13
	138	1,295	4,375
Gains on sale of businesses	**446**	280	69
Total consideration	**584**	1,575	4,444
Consideration received (receivable)[b]	**1,116**	96	(414)
Proceeds from the sale of businesses related to completed transactions	**1,700**	1,671	4,030
Deposits[c]	**26**		(146)
Proceeds from the sale of businesses	**1,726**	1,671	3,884

[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. 2015 includes $1,079 million of proceeds from our Toledo refinery partner, Husky Energy, in place of capital commitments relating to the original divestment transaction that have not been subsequently sanctioned. 2013 includes contingent consideration of $475 million relating to the disposal of the Texas City refinery.

[c] Proceeds received in the current year in advance of business disposals, less deposits received in prior years in relation to business disposals completed in the current year.

Impairments

Impairment losses and impairment reversals 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. For information on impairments recognized by joint ventures see Note 15.

Upstream

The 2015 impairment losses of $2,484 million included $761 million in Angola, of which $371 million related to the Greater Plutonio cash-generating unit (CGU), which has a recoverable amount of $2,222 million. Impairment losses also included $830 million in relation to CGUs in the North Sea, of which $328 million relates to the Andrew area CGU, which has a recoverable amount of $766 million. The impairment losses primarily arose as a result of a lower price environment in the near term, and were also affected to a lesser extent by certain technical reserves revisions and increases in decommissioning cost estimates. The 2015 impairment reversals of $1,080 million included $945 million in the North Sea business, of which $473 million related to the Eastern Trough Area Project (ETAP) CGU, which has a recoverable amount of $2,489 million. The impairment reversals mainly arose as a result of decreases in cost estimates and a reduction in the discount rate applied, offsetting the impact of lower prices in the near term. Impairment losses and reversals relate to producing assets. The recoverable amounts of the Greater Plutonio CGU, the Andrew area CGU, and the ETAP 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 recoverable amount of the Greater Plutonio 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 2014 impairment losses of $6,737 million included $4,876 million in relation to CGUs in the North Sea, of which $1,964 million related to the Valhall CGU, $660 million related to the Andrew area CGU, and $515 million related to the ETAP CGU. Impairment losses also included an $859-million impairment of our PSVM CGU in Angola, and a

$415-million impairment of the Block KG D6 CGU in India. All of the impairments related to producing

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4. Disposals and impairment continued

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 discount rate used to determine the value in use of the PSVM CGU included the 2% premium for higher-risk countries. 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.

Downstream

The 2015 impairment losses of $265 million arose principally in relation to certain manufacturing assets in our petrochemicals business and certain US midstream assets, where the expected disposal proceeds were lower than the book values.

The 2014 impairment losses of $1,264 million principally related to our Bulwer Island refinery and certain midstream assets in our fuels business, and certain manufacturing assets in our petrochemicals business.

The 2013 impairment losses of $484 million principally related to impairments of certain refineries in the US and elsewhere in our global fuels portfolio.

Other businesses and corporate

Impairment losses totalling $155 million, $317 million, and $218 million were recognized in 2015, 2014 and 2013 respectively. The amount for 2015 is principally in respect of our US wind business. 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.

5. Segmental analysis

The group s organizational structure reflects the various activities in which BP is engaged. At 31 December 2015, 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 aspects of our response to the 2010 Gulf of Mexico incident, was overseen by a board committee for all periods presented, 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. From 2016, we intend to report GCRO as part of Other businesses and corporate.

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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5. Segmental analysis continued

$ million

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	2015 Total group
Segment revenues							
Sales and other operating revenues	**43,235**	**200,569**		**2,048**		**(22,958)**	**222,894**
Less: sales and other operating revenues between segments	**(21,949)**	**(68)**		**(941)**		**22,958**	
Third party sales and other operating revenues	**21,286**	**200,501**		**1,107**			**222,894**
Earnings from joint ventures and associates after interest and tax	**192**	**491**	**1,330**	**(202)**			**1,811**
Segment results							
Replacement cost profit (loss) before interest and taxation	**(937)**	**7,111**	**1,310**	**(1,768)**	**(11,709)**	**(36)**	**(6,029)**
Inventory holding gains (losses)[a]	**(30)**	**(1,863)**	**4**				**(1,889)**
Profit (loss) before interest and taxation	**(967)**	**5,248**	**1,314**	**(1,768)**	**(11,709)**	**(36)**	**(7,918)**
Finance costs							**(1,347)**
Net finance expense relating to pensions and other post-retirement benefits							**(306)**
Profit (loss) before taxation							**(9,571)**
Other income statement items							
Depreciation, depletion and amortization							
US	**4,007**	**906**		**77**			**4,990**
Non-US	**8,866**	**1,162**		**201**			**10,229**
Charges for provisions, net of write-back of unused provisions, including change in discount rate	**824**	**611**		**228**	**11,553**		**13,216**
Segment assets							
Investments in joint ventures and associates	**8,304**	**3,214**	**5,797**	**519**			**17,834**

Additions to non-current assets[b]	**17,635**	**2,130**	**315**	**20,080**
Additions to other investments				**35**
Element of acquisitions not related to non-current assets				**(31)**
Additions to decommissioning asset				**(553)**
Capital expenditure and acquisitions, on an accruals basis	**17,082**	**2,109**	**340**	**19,531**

[a] See explanation of inventory holding gains and losses on page 124.

[b] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

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5. 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
Earnings from joint ventures and associates after interest and tax	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
Charges for provisions, net of write-back of unused provisions, including change in discount rate	260	713		323	1,329		2,625
Segment assets							
Investments in joint ventures and associates	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, on an accruals basis	19,772	3,106	903	23,781

[a] See explanation of inventory holding gains and losses on page 124.

[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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5. Segmental analysis continued

By business	Upstream	Downstream	Rosneft	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	$ million 2013 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
Earnings from joint ventures and associates after interest and tax	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
Charges for provisions, net of write-back of unused provisions, including change in discount rate	161	270		295	1,855		2,581
Segment assets							
Investments in joint ventures and associates	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, on an accruals basis	19,115	4,506	11,941	1,050			36,612

[a] See explanation of inventory holding gains and losses on page 124.

[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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5. Segmental analysis continued

			$ million
			2015
By geographical area	**US**	**Non-US**	**Total**
Revenues			
Third party sales and other operating revenues[a]	**74,162**	**148,732**	**222,894**
Other income statement items			
Production and similar taxes	**215**	**821**	**1,036**
Results			
Replacement cost profit (loss) before interest and taxation	**(12,243)**	**6,214**	**(6,029)**
Non-current assets			
Non-current assets[b c]	**67,776**	**111,106**	**178,882**
Capital expenditure and acquisitions, on an accruals basis	**5,332**	**14,199**	**19,531**

[a] Non-US region includes UK $51,550 million.
[b] Non-US region includes UK $19,152 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

			$ million
			2014
By geographical area	US	Non-US	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, on an accruals basis	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.

			$ million
			2013
By geographical area	US	Non-US	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, on an accruals basis	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.

6. Income statement analysis

			$ million
	2015	2014	2013
Interest and other income			
Interest income	**226**	258	282
Other income	**385**	585	495
	611	843	777
Currency exchange losses charged to the income statement[a]	**8**	36	180
Expenditure on research and development	**418**	663	707
Finance costs			
Interest payable	**1,065**	1,025	1,082
Capitalized at 1.75% (2014 1.94% and 2013 2%)[b]	**(179)**	(185)	(238)
Unwinding of discount on provisions and other payables	**461**	308	224
	1,347	1,148	1,068

[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 $42 million (2014 $43 million and 2013 $62 million).

7. 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
	2015	2014	2013
Exploration and evaluation costs			
Exploration expenditure written off[a]	**1,829**	3,029	2,710
Other exploration costs	**524**	603	731
Exploration expense for the year	**2,353**	3,632	3,441
Impairment losses			253
Intangible assets exploration and appraisal expenditure	**17,286**	19,344	20,865
Liabilities	**145**	227	212
Net assets	**17,141**	19,117	20,653
Capital expenditure, on an accruals basis	**1,197**	2,870	4,464
Net cash used in operating activities	**524**	603	731
Net cash used in investing activities	**1,216**	2,786	4,275

[a] 2015 included a $432-million write-off in Libya as there is significant uncertainty about the timing of future drilling operations. It also includes a $345-million write-off relating to the Gila discovery in the deepwater Gulf of Mexico and a $336-million write-off relating to the Pandora discovery in Angola as development of these prospects is considered challenging. 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 30.

The carrying amount, by location, of exploration and appraisal expenditure capitalized as intangible assets at 31 December 2015 is shown in the table below.

Carrying amount	Location
$1 - 2 billion	Angola; India
$2 - 3 billion	Canada; Egypt; Brazil
$3 - 4 billion	US Gulf of Mexico

8. Taxation

Tax on profit

			$ million
	2015	2014	2013
Current tax			
Charge for the year	**1,910**	4,444	5,724
Adjustment in respect of prior years	**(329)**	48	61
	1,581	4,492	5,785
Deferred tax			
Origination and reversal of temporary differences in the current year	**(5,090)**	(3,194)	529
Adjustment in respect of prior years	**338**	(351)	149
	(4,752)	(3,545)	678
Tax charge (credit) on profit or loss	**(3,171)**	947	6,463

In 2015, the total tax charge recognized within other comprehensive income was $1,140 million (2014 $1,481 million credit and 2013 $1,374 million charge). See Note 31 for further information. The total tax charge recognized directly in equity was $9 million (2014 $36 million charge and 2013 $33 million credit).

For information on significant estimates and judgements made in relation to taxation see Income taxes within Note 1. For information on contingent liabilities in relation to taxation see Note 32.

Reconciliation of the effective tax rate

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective tax rate of the group on profit or loss before taxation. With effect from 1 April 2015 the UK statutory corporation tax rate reduced from 21% to 20% on profits arising from activities outside the North Sea.

For 2015, the items presented in the reconciliation are affected as a result of the overall tax credit for the year and the loss before taxation. In order to provide a more meaningful analysis of the effective tax rate, the table also presents separate reconciliations for the group excluding the impacts of the Gulf of Mexico oil spill and impairment losses, and for the impacts of the Gulf of Mexico oil spill and impairment losses in isolation.

For 2014, the items presented in the reconciliation are affected 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.

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8. Taxation continued

For 2013, the effective tax rate is not affected significantly by impairment losses or the impact of the Gulf of Mexico oil spill.

$ million

	2015 excluding impacts of Gulf of Mexico oil spill and impairments	2015 impacts of Gulf of Mexico oil spill and impairments	2015	2014 excluding impairments	2014 impacts of impairments	2014	2013
Profit (loss) before taxation	**4,031**	**(13,602)**	**(9,571)**	13,166	(8,216)	4,950	30,221
Tax charge (credit) on profit or loss	**945**	**(4,116)**	**(3,171)**	5,036	(4,089)	947	6,463
Effective tax rate	**23%**	**30%**	**33%**	38%	50%	19%	21%
					% of profit or loss before taxation		
UK statutory corporation tax rate	**20**	**20**	**20**	21	21	21	23
Increase (decrease) resulting from							
UK supplementary and overseas taxes at higher or lower rates[a]		**18**	**25**	17	34	(11)	4
Tax reported in equity-accounted entities	**(10)**		**4**	(5)		(14)	(2)
Adjustments in respect of prior years	**1**			(2)		(6)	1
Movement in deferred tax not recognized	**17**	**(5)**	**(14)**	4	(3)	17	2
Tax incentives for investment	**(8)**		**3**	(4)		(10)	(2)
Gulf of Mexico oil spill non-deductible costs		**(2)**	**(3)**			1	
Permanent differences relating to disposals	**(3)**		**1**	(1)		(1)	(8)
Foreign exchange	**18**		**(8)**	4		10	2
Items not deductible for tax purposes	**10**		**(4)**	4	(2)	12	1
	(23)		**10**				

Decrease in rate of UK supplementary charge[b]							
Other	**1**	**(1)**	**(1)**				
Effective tax rate	**23**	**30**	**33**	38	50	19	21

[a] For 2015 excluding impacts of the Gulf of Mexico oil spill and impairments, the most significant countries impacting upon the rate were the US (with an applicable statutory tax rate of 35%), Angola (50%), Germany (32%), Indonesia (42%) and UK North Sea (50%). However because there were profits in some countries and losses in others, the net impact on the effective tax rate reconciliation was less than 1%. For 2014 excluding impairments, jurisdictions which contribute significantly to this item are Angola (50%), Trinidad (55%) and the US (35%). For 2013, jurisdictions which contribute significantly are Angola, the UK North Sea and Trinidad, with applicable statutory tax rates of 50%, 62% and 55% respectively.

[b] For 2015, this relates to the one-off deferred tax impact of the enactment of legislation to reduce the UK supplementary charge tax rate applicable to profits arising in the North Sea from 32% to 20%.

Deferred tax

		$ million
Analysis of movements during the year in the net deferred tax liability	**2015**	2014
At 1 January	**11,584**	16,454
Exchange adjustments	**86**	122
Charge (credit) for the year in the income statement	**(4,752)**	(3,545)
Charge (credit) for the year in other comprehensive income	**1,140**	(1,563)
Charge (credit) for the year in equity	**9**	36
Acquisitions and disposals	**(13)**	80
At 31 December	**8,054**	11,584

The following table provides an analysis of deferred tax in the income statement and the balance sheet by category of temporary difference:

					$ million
	Income statement			Balance sheet	
	2015	2014	2013	**2015**	2014
Deferred tax liability					
Depreciation	**(102)**	(2,178)	(474)	**28,712**	29,062
Pension plan surpluses	**84**	(272)	(691)	**878**	
Derivative financial instruments	**(326)**	527	99	**961**	1,089
Other taxable temporary differences	**59**	(1,805)	(298)	**1,266**	1,356
	(285)	(3,728)	(1,364)	**31,817**	31,507
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**12**	492	787	**(1,972)**	(2,761)
Decommissioning, environmental and other provisions	**(2,513)**	52	1,385	**(13,737)**	(11,237)
Derivative financial instruments	**62**	166	30	**(710)**	(575)
Tax credits	**256**	589	(174)	**(43)**	(298)
Loss carry forward	**(2,239)**	(1,397)	(343)	**(5,985)**	(3,848)
Other deductible temporary differences	**(45)**	281	357	**(1,316)**	(1,204)

		(4,467)	183	2,042	**(23,763)**	(19,923)
Net deferred tax charge (credit) and net deferred tax liability		**(4,752)**	(3,545)	678	**8,054**	11,584
Of which	deferred tax liabilities				**9,599**	13,893
	deferred tax assets				**1,545**	2,309

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8. Taxation continued

The recognition of deferred tax assets of $1,067 million (2014 $1,467 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.

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	**2015**	2014
Unused US state tax losses[a]	**9.6**	9.0
Unused tax losses other jurisdictions[b]	**2.1**	2.1
Unused tax credits	**20.4**	20.1
of which arising in the UK[c]	**17.5**	18.0
arising in the US[d]	**2.8**	2.0
Deductible temporary differences[e]	**23.2**	17.9
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	**3.9**	1.0

[a] Of the gross unused tax losses on which no deferred tax is recognized, $9.6 billion relates to US state taxes which expire in the period 2016-2035 with applicable tax rates ranging from 5% to 12%. An amendment has been made to the comparative amount.

[b] The majority of the unused tax losses have no fixed expiry date.

[c] 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.

[d] The US unused tax credits expire in the period 2016-2025.

[e] Primarily comprises fixed asset temporary differences. Substantially all of the temporary differences have no expiry date.

			$ million
Impact of previously unrecognized deferred tax or write-down of deferred tax assets on current year charge	**2015**	2014	2013
Current tax benefit relating to the utilization of previously unrecognized tax credits and losses	**123**	171	216
Deferred tax benefit relating to the recognition of previously unrecognized tax credits and losses			178
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	**768**	153	

9. Dividends

The quarterly dividend expected to be paid on 24 March 2016 in respect of the fourth quarter 2015 is 10 cents per ordinary share ($0.60 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 14 March 2016. 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		
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Dividends announced and paid in cash									
Preference shares							**2**	2	2
Ordinary shares									
March	**6.6699**	5.7065	6.0013	**10.00**	9.50	9.00	**1,708**	1,426	1,621
June	**6.5295**	5.8071	5.8342	**10.00**	9.75	9.00	**1,691**	1,572	1,399
September	**6.5488**	5.9593	5.7630	**10.00**	9.75	9.00	**1,717**	1,122	1,245
December	**6.6342**	6.3769	5.8008	**10.00**	10.00	9.50	**1,541**	1,728	1,174
	26.3824	23.8498	23.3993	**40.00**	39.00	36.50	**6,659**	5,850	5,441
Dividend announced, payable in March 2016				**10.00**			**1,841**		

The details of the scrip dividends issued are shown in the table below.

	2015	2014	2013
Number of shares issued (thousand)	**102,810**	165,644	202,124
Value of shares issued ($ million)	**642**	1,318	1,470

The financial statements for the year ended 31 December 2015 do not reflect the dividend announced on 2 February 2016 and expected to be paid in March 2016; this will be treated as an appropriation of profit in the year ended 31 December 2016.

10. Earnings per ordinary share

	Cents per share		
	2015	2014	2013
Basic earnings per share	**(35.39)**	20.55	123.87
Diluted earnings per share	**(35.39)**	20.42	123.12

Basic earnings per ordinary share amounts are calculated by dividing the profit (loss) for the year attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. The average number of shares outstanding includes certain shares that will be issuable in the future under employee share-based payment plans and excludes 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 average number of shares that are potentially issuable in connection with employee share-based payment plans using the treasury stock method. If the inclusion of potentially issuable shares would decrease loss per share, the potentially issuable shares are excluded from the weighted average number of shares outstanding used to calculate diluted earnings per share. A dilutive effect relating to potentially issuable shares has not been included, therefore, in the calculation of diluted earnings per share for 2015.

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10. Earnings per ordinary share continued

			$ million
	2015	2014	2013
Profit (loss) attributable to BP shareholders	**(6,482)**	3,780	23,451
Less: dividend requirements on preference shares	**2**	2	2
Profit (loss) for the year attributable to BP ordinary shareholders	**(6,484)**	3,778	23,449

			Shares thousand
	2015	2014	2013
Basic weighted average number of ordinary shares	**18,323,646**	18,385,458	18,931,021
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans		111,836	115,152
	18,323,646	18,497,294	19,046,173

The number of ordinary shares outstanding at 31 December 2015, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 18,412,392,432. Between 31 December 2015 and 16 February 2016, the latest practicable date before the completion of these financial statements, there was a net increase of 12,765,658 in the number of ordinary shares outstanding as a result of share issues in relation to employee share-based payment plans.

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 76-92.

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 is also shown.

Share options		**2015**		2014
	Number of options[a b] thousand	**Weighted average exercise price $**	Number of options[a b] thousand	Weighted average exercise price $
Outstanding	**70,049**	**8.54**	113,206	9.62
Exercisable	**46,520**	**10.21**	86,211	10.89
Dilutive effect	**2,659**	**n/a**	5,570	n/a

[a] Numbers of options shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).
[b] At 31 December 2015 the quoted market price of one BP ordinary share was £3.54 (2014 £4.11).

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 is also shown.

Share plans	**2015**	2014
	Number of shares[a]	Number of shares[a]
Vesting	**thousand**	thousand
Within one year	**78,823**	78,467
1 to 2 years	**76,779**	91,993
2 to 3 years	**89,654**	80,966
3 to 4 years	**41,479**	28,564
4 to 5 years	**695**	222
	287,430	280,212
Dilutive effect	**101,984**	99,917

[a] Numbers of shares shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).

There has been a net increase of 60,530,268 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2015 and 16 February 2016.

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11. 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 2015	**3,415**	**3,061**	**200,514**	**48,815**	**3,031**	**13,819**	**9,046**	**281,701**
Exchange adjustments	**(259)**	**(144)**		**(1,828)**	**(89)**	**(61)**	**(772)**	**(3,153)**
Additions	**96**	**122**	**14,574**	**1,114**	**129**	**493**	**551**	**17,079**
Acquisitions				**27**				**27**
Transfers			**1,039**					**1,039**
Reclassified as assets held for sale		**(66)**		**(1,364)**	**(31)**			**(1,461)**
Deletions	**(58)**	**(96)**	**(561)**	**(1,020)**	**(174)**	**(213)**	**(407)**	**(2,529)**
At 31 December 2015	**3,194**	**2,877**	**215,566**	**45,744**	**2,866**	**14,038**	**8,418**	**292,703**
Depreciation								
At 1 January 2015	**639**	**1,197**	**111,175**	**21,358**	**1,983**	**8,933**	**5,724**	**151,009**
Exchange adjustments	**(10)**	**(51)**		**(914)**	**(56)**	**(33)**	**(452)**	**(1,516)**
Charge for the year	**37**	**135**	**12,004**	**1,760**	**238**	**426**	**323**	**14,923**
Impairment losses	**14**	**2**	**2,113**	**225**	**1**	**283**	**7**	**2,645**
Impairment reversals			**(1,079)**	**(2)**		**(18)**	**(159)**	**(1,258)**
Transfers			**21**					**21**
Reclassified as assets held for sale		**(33)**		**(1,038)**	**(24)**			**(1,095)**
Deletions	**(38)**	**(93)**	**(403)**	**(737)**	**(58)**	**(152)**	**(303)**	**(1,784)**
At 31 December 2015	**642**	**1,157**	**123,831**	**20,652**	**2,084**	**9,439**	**5,140**	**162,945**
Net book amount at 31 December 2015	**2,552**	**1,720**	**91,735**	**25,092**	**782**	**4,599**	**3,278**	**129,758**
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
Assets held under finance leases at net book amount included above								
At 31 December 2015		**2**	**84**	**297**		**242**		**625**
At 31 December 2014		3	135	295		244		677
Assets under construction included above								
At 31 December 2015								**27,755**
At 31 December 2014								26,429

[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.

12. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2015 amounted to $10,379 million (2014 $14,590 million amended from $15,635 million previously disclosed). BP s share of capital commitments of joint ventures amounted to $586 million (2014 $369 million).

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13. Goodwill and impairment review of goodwill

		$ million
	2015	2014
Cost		
At 1 January	**12,482**	12,851
Exchange adjustments	**(237)**	(278)
Acquisitions	**5**	73
Deletions	**(14)**	(164)
At 31 December	**12,236**	12,482
Impairment losses		
At 1 January	**614**	670
Deletions	**(5)**	(56)
At 31 December	**609**	614
Net book amount at 31 December	**11,627**	11,868
Net book amount at 1 January	**11,868**	12,181

Impairment review of goodwill

		$ million
Goodwill at 31 December	**2015**	2014
Upstream	**7,812**	7,819
Downstream	**3,761**	3,968
Other businesses and corporate	**54**	81
	11,627	11,868

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
	2015	2014
Goodwill	**7,812**	7,819
Excess of recoverable amount over carrying amount	**12,894**	26,077

The table above shows the carrying amount of goodwill for the segment and the excess of the recoverable amount, based upon a fair value less costs of disposal calculation, over the carrying amount (the headroom).

The fair value less costs of disposal is based on the cash flows expected to be generated by the projected oil or natural gas production profiles up to the expected dates of cessation of production of each producing field, based on current estimates of reserves and resources, appropriately risked. Midstream and supply and trading activities and equity-accounted entities are generally not included in the impairment review of goodwill, because they are not part of the grouping of cash-generating units to which the goodwill relates and which is used to monitor the goodwill for internal management purposes. Where such activities form part of a wider Upstream cash-generating unit, they are reflected in the test. 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 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 price environment at the time that the test was performed. 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 2015 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, production volumes and the discount rate. Oil price assumptions for the first five years reflect the forward market prices at the time that the calculation was prepared. The prices used were, on average, $6.50 per barrel higher than the prices at the end of the year which are disclosed in Note 1. Gas price assumptions used for the first five years were, on average, the same as those disclosed in Note 1. Long-term price assumptions and discount rate assumptions used were as disclosed in Note 1. The fair value less costs of disposal calculations have been prepared solely for the purposes of determining whether the goodwill balance was impaired. Estimated future cash flows were prepared on the basis of certain assumptions prevailing at the time of the test. The actual outcomes may differ from the assumptions made. For example, reserves and resources estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change, and future commodity prices may differ from the forecasts used in the calculations.

13. Goodwill and impairment review of goodwill continued

The sensitivities to different variables have been estimated using certain simplifying assumptions. For example, lower oil and gas prices sensitivities do not reflect the specific impacts for each contractual arrangement and will not capture fully any favourable impacts that may arise from cost deflation. Therefore a detailed calculation at any given price or production profile may produce a different result.

It is estimated that if the oil price assumption for all future years (the first five years, and the long-term assumption from 2021 onwards) was approximately $6.50 per barrel lower in each year, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the segment. It is estimated that if the gas price assumption for all future years was approximately $0.60 per mmbtu lower in each year, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related net 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 911mmboe per year (2014 847mmboe per year). It is estimated that if production volume were to be reduced by approximately 3% for this 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 9% for the entire portfolio, an increase of 2% for all countries not classified as higher risk , 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

			2015			2014
	Lubricants	**Other**	**Total**	Lubricants	Other	Total
Goodwill	**3,109**	**652**	**3,761**	3,264	704	3,968

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 Lubricants recoverable amount performed in the most recent detailed calculation in 2013 were used for the 2015 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 BP s 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.

14. Intangible assets

$ million

	2015			2014		
	Exploration and appraisal expenditure[a]	**Other intangibles**	**Total**	Exploration and appraisal expenditure[a]	Other intangibles	Total
Cost						
At 1 January	**21,723**	**4,268**	**25,991**	21,742	3,936	25,678
Exchange adjustments		**(187)**	**(187)**		(175)	(175)
Acquisitions					455	455
Additions	**1,197**	**234**	**1,431**	2,871	394	3,265
Transfers	**(1,039)**		**(1,039)**	(993)		(993)
Reclassified as assets held for sale		**(18)**	**(18)**			
Deletions	**(2,025)**	**(242)**	**(2,267)**	(1,897)	(342)	(2,239)
At 31 December	**19,856**	**4,055**	**23,911**	21,723	4,268	25,991
Amortization						
At 1 January	**2,379**	**2,705**	**5,084**	877	2,762	3,639
Exchange adjustments		**(75)**	**(75)**		(72)	(72)
Charge for the year	**1,829**	**296**	**2,125**	3,029	304	3,333
Impairment losses					50	50
Transfers	**(21)**		**(21)**			
Reclassified as assets held for sale		**(15)**	**(15)**			
Deletions	**(1,617)**	**(230)**	**(1,847)**	(1,527)	(339)	(1,866)
At 31 December	**2,570**	**2,681**	**5,251**	2,379	2,705	5,084
Net book amount at 31 December	**17,286**	**1,374**	**18,660**	19,344	1,563	20,907
Net book amount at 1 January	**19,344**	**1,563**	**20,907**	20,865	1,174	22,039

[a] For further information see Intangible assets within Note 1 and Note 7.

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15. Investments in joint ventures

The following table provides aggregated summarized financial information relating to the group s share of joint ventures.

			$ million
	2015	2014	2013
Sales and other operating revenues	**9,588**	12,208	12,507
Profit before interest and taxation	**785**	1,210	1,076
Finance costs	**188**	125	130
Profit before taxation	**597**	1,085	946
Taxation	**625**	515	499
Profit (loss) for the year	**(28)**	570	447
Other comprehensive income	**(1)**	(15)	38
Total comprehensive income	**(29)**	555	485
Non-current assets	**11,163**	11,586	
Current assets	**2,515**	2,853	
Total assets	**13,678**	14,439	
Current liabilities	**1,855**	2,222	
Non-current liabilities	**3,500**	3,774	
Total liabilities	**5,355**	5,996	
Net assets	**8,323**	8,443	
Group investment in joint ventures			
Group share of net assets (as above)	**8,323**	8,443	
Loans made by group companies to joint ventures	**89**	310	
	8,412	8,753	

The loss for the year shown in the table above includes $711 million relating to BP s share of impairment losses recognized by joint ventures, a significant element of which relates to the Angola LNG plant.

Transactions between the group and its joint ventures are summarized below.

Sales to joint ventures						$ million
		2015		2014		2013
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	**2,841**	**245**	3,148	300	4,125	342

Purchases from joint ventures						$ million
		2015		2014		2013
Product	**Purchases**	**Amount payable**	Purchases	Amount payable	Purchases	Amount payable

		at 31 December		at 31 December		at 31 December
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**861**	**104**	907	129	503	51

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.

16. 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	
	2015	2014	2013	**2015**	2014
Rosneft	**1,330**	2,101	2,058	**5,797**	7,312
Other associates	**509**	701	684	**3,625**	3,091
	1,839	2,802	2,742	**9,422**	10,403

The associate that is material to the group at both 31 December 2015 and 2014 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 were not recognized in 2013 as a result of the discontinuance of equity accounting.

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16. 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 depository receipts are listed on the London Stock Exchange. The Russian federal government, through its investment company OJSC Rosneftegaz, owned 69.5% of the voting shares of Rosneft at 31 December 2015.

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 whose functional currency is the Russian rouble. The reduction in the group s equity-accounted investment balance for Rosneft at 31 December 2015 compared with 31 December 2014 was principally due to the weakening of the rouble compared to the US dollar, the effects of which have been recognized in other comprehensive income.

The value of BP s 19.75% shareholding in Rosneft based on the quoted market share price of $3.48 per share (2014 $3.51 per share) was $7,283 million at 31 December 2015 (2014 $7,346 million).

The following table provides summarized financial information relating to Rosneft. This information is presented on a 100% basis and reflects adjustments made by BP to Rosneft s 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. These adjustments have increased the reported profit for 2015, 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.

			$ million
			Gross amount
	2015	2014	2013
Sales and other operating revenues	**84,071**	142,856	122,866
Profit before interest and taxation	**12,253**	19,367	14,106
Finance costs	**3,696**	5,230	1,337
Profit before taxation	**8,557**	14,137	12,769
Taxation	**1,792**	3,428	2,137
Non-controlling interests	**30**	71	213
Profit for the year	**6,735**	10,638	10,419
Other comprehensive income	**(4,111)**	(13,038)	(441)
Total comprehensive income	**2,624**	(2,400)	9,978
Non-current assets	**84,689**	101,073	
Current assets	**34,891**	38,278	
Total assets	**119,580**	139,351	
Current liabilities	**25,691**	36,400	
Non-current liabilities	**63,554**	65,266	
Total liabilities	**89,245**	101,666	
Net assets	**30,335**	37,685	
Less: non-controlling interests	**982**	663	

	29,353	37,022

The group received dividends, net of withholding tax, of $271 million from Rosneft in 2015 (2014 dividends of $693 million and 2013 dividends of $456 million).

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16. Investments in associates   continued

Summarized financial information for the group s share of associates is shown below.

									$ million BP share
			2015			2014			2013
	Rosneft[a]	**Other**	**Total**	Rosneft[a]	Other	Total	Rosneft	Other	Total
Sales and other operating revenues	**16,604**	**6,000**	**22,604**	28,214	9,724	37,938	24,266	12,998	37,264
Profit before interest and taxation	**2,420**	**661**	**3,081**	3,825	938	4,763	2,786	908	3,694
Finance costs	**730**	**6**	**736**	1,033	7	1,040	264	11	275
Profit before taxation	**1,690**	**655**	**2,345**	2,792	931	3,723	2,522	897	3,419
Taxation	**354**	**146**	**500**	677	230	907	422	213	635
Non-controlling interests	**6**		**6**	14		14	42		42
Profit for the year	**1,330**	**509**	**1,839**	2,101	701	2,802	2,058	684	2,742
Other comprehensive income	**(812)**	**(2)**	**(814)**	(2,575)	10	(2,565)	(87)	2	(85)
Total comprehensive income	**518**	**507**	**1,025**	(474)	711	237	1,971	686	2,657
Non-current assets	**16,726**	**3,914**	**20,640**	19,962	2,975	22,937			
Current assets	**6,891**	**1,621**	**8,512**	7,560	2,199	9,759			
Total assets	**23,617**	**5,535**	**29,152**	27,522	5,174	32,696			
Current liabilities	**5,074**	**1,134**	**6,208**	7,189	1,614	8,803			
Non-current liabilities	**12,552**	**1,311**	**13,863**	12,890	921	13,811			
Total liabilities	**17,626**	**2,445**	**20,071**	20,079	2,535	22,614			
Net assets	**5,991**	**3,090**	**9,081**	7,443	2,639	10,082			
Less: non-controlling interests	**194**		**194**	131		131			
	5,797	**3,090**	**8,887**	7,312	2,639	9,951			
Group investment in associates									
Group share of net assets (as above)	**5,797**	**3,090**	**8,887**	7,312	2,639	9,951			

Loans made by group companies to associates		**535**	**535**		452	452
	5,797	**3,625**	**9,422**	7,312	3,091	10,403

[a] From 1 October 2014, Rosneft adopted hedge accounting in relation to a portion of highly probable future export revenue denominated in US dollars over a five-year period. Foreign exchange gains and losses arising on the retranslation of borrowings denominated in currencies other than the Russian rouble and designated as hedging instruments are recognized initially in other comprehensive income, and are reclassified to the income statement as the hedged revenue is recognized.

Transactions between the group and its associates are summarized below.

$ million

Sales to associates		**2015**		2014		2013
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	**5,302**	**1,058**	9,589	1,258	5,170	783

$ million

Purchases from associates		**2015**		2014		2013
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	**11,619**	**2,026**	22,703	2,307	21,205	3,470

In addition to the transactions shown in the table above, in 2015 the group acquired a 20% participatory interest in Taas-Yuryakh Neftegazodobycha, a Rosneft subsidiary.

The terms of the outstanding balances receivable from associates are typically 30 to 45 days. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts. Dividends receivable are not included in the table above.

The majority of the sales to and purchases from associates relate to crude oil and oil products transactions with Rosneft.

BP has commitments amounting to $11,446 million (2014 $6,946 million), primarily in relation to contracts with its associates for the purchase of transportation capacity.

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17. Other investments

				$ million
		2015		2014
	Current	**Non-current**	Current	Non-current
Equity investments[a]		**397**		420
Other	**219**	**605**	329	808
	219	**1,002**	329	1,228

[a] The majority of equity investments are unlisted.

Other non-current investments includes $605 million relating to life insurance policies (2014 $599 million) which 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.

18. Inventories

		$ million
	2015	2014
Crude oil	**3,467**	5,614
Natural gas	**251**	285
Refined petroleum and petrochemical products	**7,470**	8,975
	11,188	14,874
Supplies	**2,626**	3,051
	13,814	17,925
Trading inventories	**328**	448
	14,142	18,373
Cost of inventories expensed in the income statement	**164,790**	281,907

The inventory valuation at 31 December 2015 is stated net of a provision of $1,295 million (2014 $2,879 million) to write inventories down to their net realizable value. The net credit to the income statement in the year in respect of inventory net realizable value provisions was $1,507 million (2014 $2,625 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.

19. Trade and other receivables

				$ million
		2015		2014
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**13,682**	**72**	19,671	166
Amounts receivable from joint ventures and associates	**1,303**		1,558	
Other receivables	**5,908**	**1,249**	7,863	1,293

	20,893	**1,321**	29,092	1,459
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**686**		1,154	2,701
Other receivables	**744**	**895**	792	627
	1,430	**895**	1,946	3,328
	22,323	**2,216**	31,038	4,787

[a] See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 28 for further information.

20. Valuation and qualifying accounts

$ million

	2015		2014		2013	
	Accounts receivable	**Fixed asset investments**	Accounts receivable	Fixed asset investments	Accounts receivable	Fixed asset investments
At 1 January	**331**	**517**	343	168	489	349
Charged to costs and expenses	**243**	**195**	127	438	82	4
Charged to other accounts[a]	**(23)**	**(4)**	(24)	(2)	(4)	4
Deductions	**(104)**	**(273)**	(115)	(87)	(224)	(189)
At 31 December	**447**	**435**	331	517	343	168

[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.

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21. Trade and other payables

$ million

	2015 Current	2015 Non-current	2014 Current	2014 Non-current
Financial liabilities				
Trade payables	**16,838**		23,074	
Amounts payable to joint ventures and associates	**2,130**		2,436	
Other payables	**10,775**	**2,351**	11,832	2,985
	29,743	**2,351**	37,342	2,985
Non-financial liabilities				
Other payables	**2,206**	**559**	2,776	602
	31,949	**2,910**	40,118	3,587

Trade and other payables are predominantly interest free. See Note 28 for further information.

22. Provisions

$ million

	Decommissioning	Environmental	Litigation and claims	Clean Water Act penalties	Other	Total
At 1 January 2015	**18,720**	**2,847**	**4,739**	**3,510**	**3,082**	**32,898**
Exchange adjustments	**(356)**	**(18)**	**(9)**		**(119)**	**(502)**
New or increased provisions	**972**	**5,697**	**6,058**	**661**	**1,506**	**14,894**
Write-back of unused provisions		**(75)**	**(24)**		**(274)**	**(373)**
Unwinding of discount	**167**	**106**	**62**	**68**	**13**	**416**
Change in discount rate[a]		**(149)**	**(74)**	**(110)**		**(333)**
Utilization	**(37)**	**(392)**	**(3,494)**		**(598)**	**(4,521)**
Reclassified to other payables	**(500)**	**(459)**	**(124)**		**(204)**	**(1,287)**
Deletions	**(20)**				**(58)**	**(78)**
At 31 December 2015	**18,946**	**7,557**	**7,134**	**4,129**	**3,348**	**41,114**
Of which current	**703**	**587**	**3,023**		**841**	**5,154**
non-current	**18,243**	**6,970**	**4,111**	**4,129**	**2,507**	**35,960**
Of which Gulf of Mexico oil spill[b]		**5,919**	**6,459**	**4,129**		**16,507**

[a] Provisions for the agreements to settle all federal and state claims in relation to the Gulf of Mexico oil spill are discounted using a discount rate equal to a current interest rate that the group could obtain for a borrowing on similar terms.

[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 2015 are provisions for deferred employee compensation of $484 million (2014 $553 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.

23. 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 an employee s 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.

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, all employees who previously accrued pension benefits under a final salary plan now accrue benefits from 2015 onwards under a cash balance formula instead. Benefits previously accrued under final salary formulas are legally protected. Retired US employees typically take their pension benefit in the form of a lump sum payment upon retirement. The plan is funded and its assets are overseen by a fiduciary investment committee composed of six 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 to retired employees and their dependants (and, in certain cases, life insurance coverage); the entitlement to these benefits is usually based on the employee remaining in service until a specified age and completion of a minimum period of service.

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23. Pensions and other post-retirement benefits continued

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 an employee s 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 legal agreements between BP and the works council or between BP and the trade union.

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 2015 the aggregate level of contributions was $1,066 million (2014 $1,252 million and 2013 $1,272 million). The aggregate level of contributions in 2016 is expected to be approximately $1,050 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 seven years is agreed. The funding agreement can be terminated unilaterally by either party with two years notice. Contractually committed funding therefore represents nine years of future contributions, which amounted to $4,374 million at 31 December 2015, of which $1,437 million relates to past service. 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 220. The surplus relating to the primary UK pension plan is recognized on the balance sheet on the basis that the company is entitled to a refund of any remaining assets once all members have left the plan.

Pension contributions in the US are determined by legislation and are supplemented by discretionary contributions. All of the contributions made into the US pension plan in 2015 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 2015.

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 2015. The UK plans are subject to a formal actuarial valuation every three years; valuations are required more frequently in many other countries. The most recent formal actuarial valuation of the UK pension plans was as at 31 December 2014. 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		
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Discount rate for plan liabilities	**3.9**	3.6	4.6	**4.0**	3.7	4.3	**2.4**	2.0	3.6
Rate of increase in salaries	**4.4**	4.5	5.1	**3.9**	4.0	3.9	**3.2**	3.4	3.4
Rate of increase for pensions in payment	**3.0**	3.0	3.3				**1.6**	1.8	1.8
Rate of increase in deferred pensions	**3.0**	3.0	3.3				**0.6**	0.7	0.7
Inflation for plan liabilities	**3.0**	3.0	3.3	**1.5**	1.6	2.1	**1.8**	2.0	2.0

%

Financial assumptions used to determine benefit expense	UK			US			Eurozone		
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Discount rate for plan service cost	**3.9**	4.8	4.4	**3.8**	4.6	3.3	**2.3**	3.9	3.5
Discount rate for plan other finance expense	**3.6**	4.6	4.4	**3.7**	4.3	3.3	**2.0**	3.6	3.5
Inflation for plan service cost	**3.1**	3.4	3.1	**1.6**	2.1	2.4	**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. In other countries, including the Eurozone, 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.

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		
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Life expectancy at age 60 for a male currently aged 60	**28.5**	28.3	27.8	**25.7**	25.6	24.9	**24.9**	24.7	24.4
Life expectancy at age 60 for a male currently aged 40	**31.0**	30.9	30.7	**27.5**	27.4	26.4	**27.5**	27.3	26.9
Life expectancy at age 60 for a female currently aged 60	**29.5**	29.4	29.5	**29.2**	29.1	26.5	**28.8**	28.7	28.5
Life expectancy at age 60 for a female currently aged 40	**31.9**	31.8	32.2	**30.9**	30.9	27.3	**31.2**	31.1	30.7

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.

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23. Pensions and other post-retirement benefits continued

A significant proportion of the assets are held in equities, which are expected to generate a higher level of return over the long term, with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified.

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 the asset portfolio with the pension liabilities. There is a similar agreement in place in the US. During 2015, the UK and the US plans switched 8% and 5% respectively from equities to bonds.

In 2015, BP s primary plan in the UK adopted a more formal liability driven investment (LDI) approach for part of the portfolio, a form of investing designed to match the movement in pension plan assets with the impact of interest rate changes and inflation assumption changes on the projected benefit obligation.

The current asset allocation policy for the major plans at 31 December 2015 was as follows:

	UK	US
Asset category	%	%
Total equity (including private equity)	**62**	**55**
Bonds/cash (including LDI)	**31**	**45**
Property/real estate	**7**	

The amounts invested under the LDI programme as at 31 December 2015 were $329 million of government-issued nominal bonds and $6,421 million of index-linked bonds. This is partly funded by short-term sale and repurchase agreements, proceeds from which are shown separately in the table below.

In addition, the primary UK plan entered into interest rate swaps in the year to offset the long-term fixed interest rate exposure for $2,651 million of the corporate bond portfolio. The $17 million fair value of the swaps as at 31 December 2015 is included in other assets in the table below.

Some of the group s pension plans in other countries also use derivative financial instruments as part of their asset mix to manage the level of risk.

The group s main pension plans do not invest directly in either securities or property/real estate of the company or of any subsidiary.

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 143.

$
million

	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2015					
Listed equities developed markets	**13,474**	**2,329**	**423**	**371**	**16,597**
emerging markets	**2,305**	**226**	**49**	**50**	**2,630**
Private equity	**2,933**	**1,522**	**1**	**4**	**4,460**
Government issued nominal bonds	**393**	**1,527**	**685**	**492**	**3,097**
Government issued index-linked bonds	**6,425**		**5**		**6,430**
Corporate bonds	**4,357**	**1,717**	**551**	**367**	**6,992**
Property	**2,453**	**6**	**48**	**58**	**2,565**
Cash	**564**	**116**	**10**	**139**	**829**
Other	**110**	**67**	**102**	**50**	**329**
Debt (repurchase agreements) used to fund liability driven investments	**(1,791)**				**(1,791)**
	31,223	**7,510**	**1,874**	**1,531**	**42,138**
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
Government issued 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
Government issued 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

[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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23. Pensions and other post-retirement benefits continued

					$ million 2015
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit (loss) before interest and taxation					
Current service cost[a]	485	371	96	96	1,048
Past service cost[b]	12	(27)	47	(7)	25
Settlement			(1)	(3)	(4)
Operating charge relating to defined benefit plans	497	344	142	86	1,069
Payments to defined contribution plans	31	205	8	41	285
Total operating charge	528	549	150	127	1,354
Interest income on plan assets[a]	(1,124)	(289)	(37)	(55)	(1,505)
Interest on plan liabilities	1,146	423	151	91	1,811
Other finance expense	22	134	114	36	306
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	315	(139)	25	33	234
Change in financial assumptions underlying the present value of the plan liabilities	2,054	607	592	213	3,466
Change in demographic assumptions underlying the present value of the plan liabilities		60	15		75
Experience gains and losses arising on the plan liabilities	336	(48)	47	29	364
Remeasurements recognized in other comprehensive income	2,705	480	679	275	4,139
Movements in benefit obligation during the year					
Benefit obligation at 1 January	32,416	11,875	8,327	2,638	55,256
Exchange adjustments	(1,451)		(843)	(294)	(2,588)
Operating charge relating to defined benefit plans	497	344	142	86	1,069
Interest cost	1,146	423	151	91	1,811
Contributions by plan participants[c]	32		2	5	39
Benefit payments (funded plans)[d]	(1,269)	(1,124)	(81)	(178)	(2,652)
Benefit payments (unfunded plans)[d]	(7)	(256)	(306)	(26)	(595)
Acquisitions				9	9
Reclassified as assets held for sale			(98)		(98)
Remeasurements	(2,390)	(619)	(654)	(242)	(3,905)
Benefit obligation at 31 December[a e]	28,974	10,643	6,640	2,089	48,346
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	31,773	8,355	1,973	1,735	43,836
Exchange adjustments	(1,506)		(205)	(186)	(1,897)
Interest income on plan assets[a]	1,124	289	37	55	1,505
Contributions by plan participants[c]	32		2	5	39
Contributions by employers (funded plans)	754	129	123	60	1,066

Benefit payments (funded plans)[d]	**(1,269)**	**(1,124)**	**(81)**	**(178)**	**(2,652)**
Acquisitions				**7**	**7**
Remeasurements[f]	**315**	**(139)**	**25**	**33**	**234**
Fair value of plan assets at 31 December[g]	**31,223**	**7,510**	**1,874**	**1,531**	**42,138**
Surplus (deficit) at 31 December	**2,249**	**(3,133)**	**(4,766)**	**(558)**	**(6,208)**
Represented by					
Asset recognized	**2,516**	**66**	**25**	**40**	**2,647**
Liability recognized	**(267)**	**(3,199)**	**(4,791)**	**(598)**	**(8,855)**
	2,249	**(3,133)**	**(4,766)**	**(558)**	**(6,208)**
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	**2,506**	**49**	**(254)**	**(187)**	**2,114**
Unfunded	**(257)**	**(3,182)**	**(4,512)**	**(371)**	**(8,322)**
	2,249	**(3,133)**	**(4,766)**	**(558)**	**(6,208)**
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	**(28,717)**	**(7,461)**	**(2,128)**	**(1,718)**	**(40,024)**
Unfunded	**(257)**	**(3,182)**	**(4,512)**	**(371)**	**(8,322)**
	(28,974)	**(10,643)**	**(6,640)**	**(2,089)**	**(48,346)**

[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 have arisen from restructuring programmes and represent a combination of credits as a result of the curtailment in the pension arrangements of a number of employees mostly in the US and Trinidad and charges for special termination benefits representing the increased liability arising as a result of early retirements mostly in the UK and Eurozone.

[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 $3,128 million benefits and $57 million settlements, plus $62 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for the US is made up of $8,061 million for pension liabilities and $2,582 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,151 million for pension liabilities in Germany which is largely unfunded.

[f] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.

[g] The fair value of plan assets includes borrowings related to the LDI programme as described on page 142.

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23. Pensions and other post-retirement benefits continued

					$ million 2014
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit (loss) 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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23. Pensions and other post-retirement benefits continued

					$ million 2013
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit (loss) before interest and taxation					
Current service cost[a]	497	407	81	96	1,081
Past service cost	(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

[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 2015, reimbursement balances due from or to other companies in respect of pensions amounted to $377 million reimbursement assets (2014 $426 million) and $13 million reimbursement liabilities (2014 $16 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 2015 for the group s plans would have had the effects shown in the table below. The effects shown for the expense in 2016 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 2016	**(416)**	**387**
Effect on pension and other post-retirement benefit obligation at 31 December 2015	**(6,897)**	**8,911**
Inflation rate[b]		
Effect on pension and other post-retirement benefit expense in 2016	**408**	**(312)**
Effect on pension and other post-retirement benefit obligation at 31 December 2015	**6,996**	**(5,523)**
Salary growth		
Effect on pension and other post-retirement benefit expense in 2016	**112**	**(99)**
Effect on pension and other post-retirement benefit obligation at 31 December 2015	**1,135**	**(1,004)**

[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.

[b] The amounts presented reflect the total impact of an inflation rate change on the assumptions for rate of increase in salaries, pensions in payment and deferred pensions.

One additional year of longevity in the mortality assumptions would increase the 2016 pension and other post-retirement benefit expense by $60 million and the pension and other post-retirement benefit obligation at 31 December 2015 by $1,329 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 2025 and the weighted average duration of the defined benefit obligations at 31 December 2015 are as follows:

					$ million
Estimated future benefit payments	UK	US	Eurozone	Other	Total
2016	**1,061**	**966**	**363**	**120**	**2,510**
2017	**1,098**	**838**	**345**	**117**	**2,398**
2018	**1,150**	**846**	**337**	**121**	**2,454**
2019	**1,188**	**839**	**327**	**125**	**2,479**
2020	**1,210**	**834**	**319**	**127**	**2,490**
2021-2025	**6,575**	**3,966**	**1,517**	**667**	**12,725**
					years
Weighted average duration	**18.2**	**9.4**	**14.0**	**14.0**	

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24. Cash and cash equivalents

		$ million
	2015	2014
Cash	**4,653**	5,112
Term bank deposits	**16,749**	18,392
Cash equivalents	**4,987**	6,259
	26,389	29,763

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 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 2015 includes $2,439 million (2014 $2,264 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 $4,329 million (2014 $3,852 million) of cash and cash equivalents outside the UK and it is not expected that any significant tax will arise on repatriation.

25. Finance debt

						$ million
			2015			2014
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**6,898**	**45,567**	**52,465**	6,831	45,240	52,071
Net obligations under finance leases	**46**	**657**	**703**	46	737	783
	6,944	**46,224**	**53,168**	6,877	45,977	52,854

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 $5,942 million (2014 $6,343 million) and issued commercial paper of $869 million (2014 $444 million). Finance debt does not include accrued interest, which is reported within other payables.

At 31 December 2015, $122 million (2014 $137 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**
	Amount	**Amount**	**Amount**

	Weighted average interest rate %	Weighted average time for which rate is fixed Years	$ million	Weighted average interest rate %	$ million	$ million
						2015
US dollar	**3**	**4**	**10,442**	**1**	**40,623**	**51,065**
Other currencies	**6**	**17**	**826**	**1**	**1,277**	**2,103**
			11,268		**41,900**	**53,168**
						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

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 2015, 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 majority of the group s long-term borrowings are 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 and such measurements are therefore categorized in level 2 of the fair value hierarchy. 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 and are consequently categorized in level 2 of the fair value hierarchy.

				$ million
		2015		2014
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**956**	**956**	487	487
Long-term borrowings	**51,404**	**51,509**	51,995	51,584
Net obligations under finance leases	**1,178**	**703**	1,343	783
Total finance debt	**53,538**	**53,168**	53,825	52,854

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26. 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.

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.

We aim to maintain the net debt ratio, with some flexibility, at around 20%. We expect the net debt ratio to be above 20% while oil prices remain weak. At 31 December 2015, the net debt ratio was 21.6% (2014 16.7%).

		$ million
At 31 December	**2015**	2014
Gross debt	**53,168**	52,854
Less: fair value asset (liability) of hedges related to finance debt[a]	**(379)**	445
	53,547	52,409
Less: cash and cash equivalents	**26,389**	29,763
Net debt	**27,158**	22,646
Equity	**98,387**	112,642
Net debt ratio	**21.6%**	16.7%

[a] Derivative financial instruments entered into for the purpose of managing interest rate and foreign currency exchange risk associated with net debt with a fair value liability position of $1,617 million (2014 liability of $774 million) are not included in the calculation of net debt shown above as hedge accounting was not applied for these instruments.

An analysis of changes in net debt is provided below.

						$ million
			2015			2014
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	**(52,409)**	**29,763**	**(22,646)**	(47,715)	22,520	(25,195)
Exchange adjustments	**1,065**	**(672)**	**393**	1,160	(671)	489
Net cash flow	**(2,220)**	**(2,702)**	**(4,922)**	(5,419)	7,914	2,495

Other movements	**17**		**17**	(435)		(435)
At 31 December	**(53,547)**	**26,389**	**(27,158)**	(52,409)	29,763	(22,646)

[a] Including the fair value of associated derivative financial instruments for which hedge accounting is applied.

27. Operating leases

The cost recognized in relation to minimum lease payments for the year was $6,008 million (2014 $6,324 million and 2013 $5,961 million).

The future minimum lease payments at 31 December 2015, before deducting related rental income from operating sub-leases of $166 million (2014 $234 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	**2015**	2014
Payable within		
1 year	**4,144**	5,401
2 to 5 years	**7,743**	9,916
Thereafter	**3,535**	3,468
	15,422	18,785

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 2015, the future minimum lease payments relating to drilling rigs amounted to $4,783 million (2014 $8,180 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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28. 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 2015	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	**17**		**397**					**397**
other	**17**		**219**		**605**			**824**
Loans		**801**						**801**
Trade and other receivables	**19**	**22,214**						**22,214**
Derivative financial instruments	**29**				**7,700**	**951**		**8,651**
Cash and cash equivalents	**24**	**21,402**	**2,859**	**2,128**				**26,389**
Financial liabilities								
Trade and other payables	**21**						**(32,094)**	**(32,094)**
Derivative financial instruments	**29**				**(6,139)**	**(1,383)**		**(7,522)**
Accruals							**(7,151)**	**(7,151)**
Finance debt	**25**						**(53,168)**	**(53,168)**
		44,417	**3,475**	**2,128**	**2,166**	**(432)**	**(92,413)**	**(40,659)**
At 31 December 2014								
Financial assets								
Other investments equity shares	17		420					420
other	17		538		599			1,137
Loans		992						992
Trade and other receivables	19	30,551						30,551
Derivative financial instruments	29				8,511	1,096		9,607
Cash and cash equivalents	24	23,504	2,989	3,270				29,763
Financial liabilities								
	21						(40,327)	(40,327)

Trade and other payables								
Derivative financial instruments	29				(6,100)	(788)		(6,888)
Accruals							(7,963)	(7,963)
Finance debt	25						(52,854)	(52,854)
		55,047	3,947	3,270	3,010	308	(101,144)	(35,562)

The fair value of finance debt is shown in Note 25. 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, LNG 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 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.

28. 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.

(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, Eurozone and Australian operational requirements, for which hedging programmes are in place and hedge accounting is applied as outlined in Note 1.

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, Australian dollar and South Korean won. At 31 December 2015 the most significant open contracts in place were for $627 million sterling (2014 $321 million sterling).

For other UK, Eurozone 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 2015, the open positions relating to cylinders consisted of receive sterling, pay US dollar cylinders for $2,479 million (2014 $2,787 million); receive euro, pay US dollar cylinders for $560 million (2014 $867 million); receive Australian dollar, pay US dollar cylinders for $312 million (2014 $418 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 2015, the total foreign currency net borrowings not swapped into US dollars amounted to $826 million (2014 $871 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 2015 was 79% of total finance debt outstanding (2014 71%). The weighted average interest rate on finance debt at 31 December 2015 was 2% (2014 2%) and the weighted average maturity of fixed rate debt was five years (2014 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 2016, it is estimated that the group s finance costs for 2016 would increase by approximately $419 million (2014 $377 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 the outstanding exposure incremental to that recognized on the balance sheet at 31 December 2015 was $35 million (2014 $83 million) in respect of liabilities of joint ventures and associates and $163 million (2014 $244 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.

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 2015, the group had in place credit enhancements designed to mitigate approximately $10.9 billion of credit risk (2014 $10.8 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.

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28. Financial instruments and financial risk factors continued

Management information used to monitor credit risk indicates that 81% (2014 82%) of total unmitigated credit exposure relates to counterparties of investment-grade credit quality.

		$ million
Trade and other receivables at 31 December	**2015**	2014
Neither impaired nor past due	**21,064**	28,519
Impaired (net of provision)	**22**	37
Not impaired and past due in the following periods		
within 30 days	**414**	841
31 to 60 days	**75**	249
61 to 90 days	**118**	178
over 90 days	**521**	727
	22,214	30,551

Movements in the impairment provision for trade receivables are shown in Note 20.

Financial instruments subject to offsetting, enforceable master netting arrangements and similar agreements

The following table shows the amounts recognized for financial assets and liabilities which are subject to offsetting arrangements on a gross basis, 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 presented in the table to show the total net exposure of the group.

$ million

				Related amounts not set off in the balance sheet		
At 31 December 2015	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the balance sheet	Master netting arrangements	Cash collateral (received) pledged	Net amount
Derivative assets	**10,206**	**(1,859)**	**8,347**	**(1,109)**	**(297)**	**6,941**
Derivative liabilities	**(9,280)**	**1,859**	**(7,421)**	**1,109**		**(6,312)**
Trade receivables	**7,091**	**(3,689)**	**3,402**	**(322)**	**(161)**	**2,919**
Trade payables	**(5,720)**	**3,689**	**(2,031)**	**322**		**(1,709)**
At 31 December 2014						
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)

(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, generally 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 Ratings long-term credit rating for BP is A negative (stable outlook) and Moody s Investors Service rating is A2 (rating under review from positive).

During 2015, $8 billion of long-term taxable bonds were issued with terms ranging from 1 to 11 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 $26.4 billion at 31 December 2015 (2014 $29.8 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2015, 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 2017. These facilities were renegotiated during 2015 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 $6,850 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 2015 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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28. 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

	2015				2014			
	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	**29,743**	**6,261**	**6,944**	**928**	37,342	7,102	6,877	892
1 to 2 years	**971**	**380**	**5,796**	**812**	708	493	6,311	776
2 to 3 years	**1,231**	**138**	**6,208**	**704**	757	119	5,652	672
3 to 4 years	**56**	**98**	**6,103**	**592**	1,446	76	5,226	578
4 to 5 years	**17**	**74**	**6,354**	**478**	23	41	6,056	479
5 to 10 years	**38**	**167**	**17,651**	**1,068**	24	95	19,504	1,111
Over 10 years	**38**	**33**	**4,112**	**402**	27	37	3,228	521
	32,094	**7,151**	**53,168**	**4,984**	40,327	7,963	52,854	5,029

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 29. 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 the timing of cash outflows for derivative financial instruments entered into for the purpose of managing interest rate and foreign currency exchange risk associated with net debt, whether or not hedge accounting is applied, based upon contractual payment dates. The amounts reflect 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 $15,706 million at 31 December 2015 (2014 $14,615 million) to be received on the same day as the related cash outflows. For further information on our derivative financial instruments, see Note 29.

$ million

	2015	2014
Within one year	**2,959**	293
1 to 2 years	**2,685**	2,959
2 to 3 years	**1,505**	2,690
3 to 4 years	**1,700**	1,505
4 to 5 years	**1,678**	1,700

5 to 10 years	**5,500**	5,764
Over 10 years	**2,739**	1,325
	18,766	16,236

29. 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 28. 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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29. 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

	2015 Fair value asset	2015 Fair value liability	2014 Fair value asset	2014 Fair value liability
Derivatives held for trading				
Currency derivatives	**144**	**(1,811)**	122	(902)
Oil price derivatives	**2,390**	**(1,257)**	3,133	(1,976)
Natural gas price derivatives	**3,942**	**(2,536)**	3,859	(2,518)
Power price derivatives	**920**	**(434)**	922	(404)
Other derivatives	**292**		389	
	7,688	**(6,038)**	8,425	(5,800)
Embedded derivatives				
Commodity price contracts	**12**	**(101)**	86	(300)
	12	**(101)**	86	(300)
Cash flow hedges				
Currency forwards, futures and cylinders	**9**	**(71)**	1	(161)
Cross-currency interest rate swaps		**(147)**		(97)
	9	**(218)**	1	(258)
Fair value hedges				
Currency forwards, futures and swaps	**33**	**(1,108)**	78	(518)
Interest rate swaps	**909**	**(57)**	1,017	(12)
	942	**(1,165)**	1,095	(530)
	8,651	**(7,522)**	9,607	(6,888)
Of which current	**4,242**	**(3,239)**	5,165	(3,689)
non-current	**4,409**	**(4,283)**	4,442	(3,199)

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 28.

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
							2015
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**132**	**10**	**1**	**1**			**144**
Oil price derivatives	**1,729**	**432**	**130**	**58**	**37**	**4**	**2,390**
Natural gas price derivatives	**1,707**	**639**	**390**	**283**	**202**	**721**	**3,942**
Power price derivatives	**459**	**164**	**103**	**79**	**47**	**68**	**920**
Other derivatives	**182**	**110**					**292**
	4,209	**1,355**	**624**	**421**	**286**	**793**	**7,688**

							$ 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

At both 31 December 2015 and 2014 the group had contingent consideration receivable in respect of the disposal of the Texas City refinery. 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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29. Derivative financial instruments continued

Derivative liabilities held for trading have the following fair values and maturities.

$ million

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	2015 Total
Currency derivatives	**(499)**	**(2)**	**(2)**	**(347)**	**(79)**	**(882)**	**(1,811)**
Oil price derivatives	**(1,053)**	**(163)**	**(26)**	**(10)**	**(2)**	**(3)**	**(1,257)**
Natural gas price derivatives	**(1,037)**	**(382)**	**(210)**	**(146)**	**(162)**	**(599)**	**(2,536)**
Power price derivatives	**(246)**	**(70)**	**(31)**	**(34)**	**(17)**	**(36)**	**(434)**
	(2,835)	**(617)**	**(269)**	**(537)**	**(260)**	**(1,520)**	**(6,038)**

$ million

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	2014 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)

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

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	2015 Total
Fair value of derivative assets							
Level 1	**109**						**109**
Level 2	**4,946**	**1,137**	**402**	**213**	**68**	**50**	**6,816**
Level 3	**684**	**449**	**271**	**240**	**230**	**748**	**2,622**
	5,739	**1,586**	**673**	**453**	**298**	**798**	**9,547**

Less: netting by counterparty	**(1,530)**	**(231)**	**(49)**	**(32)**	**(12)**	**(5)**	**(1,859)**
	4,209	**1,355**	**624**	**421**	**286**	**793**	**7,688**
Fair value of derivative liabilities							
Level 1	**(104)**						**(104)**
Level 2	**(4,083)**	**(700)**	**(177)**	**(423)**	**(124)**	**(889)**	**(6,396)**
Level 3	**(178)**	**(148)**	**(141)**	**(146)**	**(148)**	**(636)**	**(1,397)**
	(4,365)	**(848)**	**(318)**	**(569)**	**(272)**	**(1,525)**	**(7,897)**
Less: netting by counterparty	**1,530**	**231**	**49**	**32**	**12**	**5**	**1,859**
	(2,835)	**(617)**	**(269)**	**(537)**	**(260)**	**(1,520)**	**(6,038)**
Net fair value	**1,374**	**738**	**355**	**(116)**	**26**	**(727)**	**1,650**

$ 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

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29. 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 2015	**246**	**181**	**214**	**389**	**1,030**
Gains (losses) recognized in the income statement	**(24)**	**272**	**79**	**92**	**419**
Inception fair value of new contracts	**126**	**14**	**87**		**227**
Settlements	**(20)**	**(40)**	**(72)**	**(189)**	**(321)**
Transfers out of level 3		**(107)**	**(23)**		**(130)**
Net fair value of contracts at 31 December 2015	**328**	**320**	**285**	**292**	**1,225**

					$ 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	270	133	79	94	576
Inception fair value of new contracts	80	19	62		161
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

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2015 was a $293 million gain (2014 $456 million gain related to derivatives still held at 31 December 2014).

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 $5,508 million (2014 $6,154 million net gain and 2013 $587 million net gain). 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 has embedded derivatives relating to certain natural gas contracts. The fair value gain on commodity price embedded derivatives included within distribution and administration expenses was $120 million (2014 gain of $430 million, 2013 gain of $459 million).

Cash flow hedges

At 31 December 2015, the group held currency forwards, futures contracts and cylinders and cross-currency interest rate swaps that were being used to hedge the foreign currency risk of highly probable forecast transactions and floating rate finance debt. Note 28 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 2015 in relation to these cash flow hedges consist of deferred losses of $55 million maturing in 2016, deferred losses of $15 million maturing in 2017 and deferred losses of $3 million maturing in 2018 and beyond.

Two of the contracts to acquire an 18.5% interest in Rosneft, which completed in March 2013, were designated as hedging instruments in a cash flow hedge. A cumulative charge of $651 million has been recognized in other comprehensive income, of which a charge of $2,061 million arose in 2013. This loss will only be reclassified to the income statement if the investment in Rosneft is either sold or impaired.

Fair value hedges

At 31 December 2015, 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 2015 was $788 million (2014 $14 million loss and 2013 $1,240 million loss) offset by a gain on the fair value of the finance debt of $833 million (2014 $8 million gain and 2013 $1,228 million gain).

The interest rate and cross-currency interest rate swaps mature within one to eleven 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 28 outlines the group s approach to interest rate and foreign currency exchange risk management.

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30. Called-up share capital

The allotted, called up and fully paid share capital at 31 December was as follows:

Issued	**2015** Shares thousand	**2015** $ million	2014 Shares thousand	2014 $ million	2013 Shares thousand	2013 $ 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	**20,005,961**	**5,002**	20,426,632	5,108	20,959,159	5,240
Issue of new shares for the scrip dividend programme	**102,810**	**26**	165,644	41	202,124	51
Issue of new shares for employee share-based payment plans[b]			25,598	6	18,203	5
Repurchase of ordinary share capital[c]			(611,913)	(153)	(752,854)	(188)
At 31 December	**20,108,771**	**5,028**	20,005,961	5,002	20,426,632	5,108
		5,049		5,023		5,129

[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 in 2014 and $116 million in 2013.

[c] There were no shares repurchased in 2015 (2014 shares were repurchased for a total consideration of $4,796 million, including transaction costs of $26 million and 2013 shares were repurchased for a total consideration of $5,493 million, including transaction costs of $30 million). All shares purchased were for cancellation.

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

Treasury shares[a]

	2015	2014	2013

	Shares thousand	**Nominal value $ million**	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,811,297**	**453**	1,833,544	458	1,864,510	466
Purchases for settlement of employee share plans	**51,142**	**13**	49,559	12	38,766	9
Shares re-issued for employee share-based payment plans	**(106,112)**	**(27)**	(71,806)	(17)	(69,732)	(17)
At 31 December	**1,756,327**	**439**	1,811,297	453	1,833,544	458
Of which shares held in treasury by BP	**1,727,763**	**432**	1,771,103	443	1,787,939	447
shares held in ESOP trusts	**18,453**	**4**	34,169	9	32,748	8
shares held by BP[b]	**10,111**	**3**	6,025	1	12,857	3

[a] See Note 31 for definition of treasury shares.
[b] Held by the group in the form of ADSs to meet the requirements of employee share-based payment plans in the US.
For each year presented, the balance at 1 January represents the maximum number of shares held in treasury by BP during the year, representing 8.9% (2014 8.8% and 2013 8.7%) of the called-up ordinary share capital of the company.

During 2015, the movement in shares held in treasury by BP represented less than 0.2% (2014 less than 0.1% and 2013 less than 0.2%) of the ordinary share capital of the company.

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31. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2015	**5,023**	**10,260**	**1,413**	**27,206**	**43,902**
Profit (loss) for the year					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)[a]					
Available-for-sale investments (including recycling)					
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	**26**	**(26)**			
Share-based payments, net of tax[b]					
Share of equity-accounted entities changes in equity, net of tax					
Transactions involving non-controlling interests					
At 31 December 2015	**5,049**	**10,234**	**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 2014	5,129	10,061	1,260	27,206	43,656
Profit (loss) 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 (loss) 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

[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
(20,719)	(3,409)	1	(898)	(897)	92,564	111,441	1,201	112,642
					(6,482)	(6,482)	82	(6,400)
	(3,858)					(3,858)	(41)	(3,899)
		1		1		1		1
			73	73		73		73
					(814)	(814)		(814)
					80	80		80
					2,742	2,742		2,742
					(1)	(1)		(1)
	(3,858)	1	73	74	(4,475)	(8,259)	41	(8,218)
					(6,659)	(6,659)	(91)	(6,750)
755					(99)	656		656
					40	40		40
					(3)	(3)	20	17
(19,964)	(7,267)	2	(825)	(823)	81,368	97,216	1,171	98,387

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

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31. 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.

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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31. 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
			2015
	Pre-tax	**Tax**	**Net of tax**
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	**(4,096)**	**197**	**(3,899)**
Available-for-sale investments (including recycling)	**1**		**1**
Cash flow hedges (including recycling)	**93**	**(20)**	**73**
Share of items relating to equity-accounted entities, net of tax	**(814)**		**(814)**
Other		**80**	**80**
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	**4,139**	**(1,397)**	**2,742**
Share of items relating to equity-accounted entities, net of tax	**(1)**		**(1)**
Other comprehensive income	**(678)**	**(1,140)**	**(1,818)**

			$ 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)

32. 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 2015 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 28.

In the normal course of the group s business, legal proceedings are pending or may be brought against BP group entities arising out of current and past operations, including matters related to commercial disputes, product liability, antitrust, commodities trading, premises-liability claims, consumer protection, general environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. BP believes that the impact of these legal proceedings on the group s results of operations, liquidity or financial position will not be material.

With respect to lead pigment in paint in particular, Atlantic Richfield, a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property. Although it is not possible to predict the outcome of the legal proceedings, Atlantic Richfield believes it has valid defences that render the incurrence of a liability remote; however, the amounts claimed and the costs of implementing the remedies sought in the various cases could be substantial. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. Atlantic Richfield intends to defend such actions vigorously.

The group files tax returns in many jurisdictions throughout the world. Various tax authorities are currently examining the group s tax returns. Tax returns contain matters that could be subject to differing interpretations of applicable tax laws and regulations and the resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete. While it is difficult to predict the ultimate outcome in some cases, the group does not anticipate that there will be any material impact upon the group s results of operations, financial position or liquidity.

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32. Contingent liabilities continued

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. Typically, losses will therefore be borne as they arise rather than being spread over time through insurance premiums. Some risks are insured with third parties and reinsured through group insurance companies. The position is reviewed periodically.

33. Remuneration of senior management and non-executive directors

Remuneration of directors

			$ million
	2015	2014	2013
Total for all directors			
Emoluments	**10**	14	16
Amounts awarded under incentive schemes[a]	**14**	10	2
Total	**24**	24	18

[a] Excludes amounts relating to past directors.

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.

Pension contributions

During 2015 one executive director participated in a non-contributory defined benefit pension plan established for UK employees by a separate trust fund to which contributions are made by BP based on actuarial advice. One executive director participated in 2015 in a US defined benefit pension plan and retirement savings plans established for US employees.

Further information

Full details of individual directors remuneration are given in the Directors remuneration report on page 76.

Remuneration of directors and senior management

			$ million
	2015	2014	2013
Total for senior management and non-executive directors			
Short-term employee benefits	**33**	34	36
Pensions and other post-retirement benefits	**4**	3	3
Share-based payments	**36**	34	43
Total	**73**	71	82

Senior management comprises members of the executive team, see pages 60-61 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. There was no compensation for loss of office included in Short-term employee benefits in 2015 (2014 $1.5 million and 2013 $3 million).

Pensions and other post-retirement benefits

The amounts represent the estimated cost to the group of providing 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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34. Employee costs and numbers

			$ million
Employee costs	**2015**	2014	2013
Wages and salaries[a]	**9,556**	10,710	10,161
Social security costs	**879**	983	958
Share-based payments[b]	**833**	689	719
Pension and other post-retirement benefit costs	**1,660**	1,554	1,816
	12,928	13,936	13,654

Average number of employees[c]	**2015**			2014			2013		
	US	**Non-US**	**Total**	US	Non-US	Total	US	Non-US	Total
Upstream	**7,900**	**15,100**	**23,000**	9,100	15,600	24,700	9,400	15,100	24,500
Downstream[d e]	**7,800**	**38,200**	**46,000**	8,200	39,900	48,100	9,300	39,800	49,100
Other businesses and corporate[e f g]	**1,700**	**11,900**	**13,600**	1,800	10,100	11,900	2,000	9,000	11,000
	17,400	**65,200**	**82,600**	19,100	65,600	84,700	20,700	63,900	84,600

[a] Includes termination payments of $857 million (2014 $527 million and 2013 $212 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 15,000 (2014 14,200 and 2013 14,100) service station staff.

[e] Around 2,000 employees from the global business services organization were reallocated from Downstream to Other businesses and corporate during 2015.

[f] Includes 5,600 (2014 5,100 and 2013 4,300) agricultural, operational and seasonal workers in Brazil.

[g] Includes employees of the Gulf Coast Restoration Organization.

35. Auditor s remuneration

			$ million
Fees Ernst & Young	**2015**	2014	2013
The audit of the company annual accounts[a]	**27**	27	26
The audit of accounts of subsidiaries of the company	**13**	13	13
Total audit	**40**	40	39
Audit-related assurance services[b]	**7**	7	8
Total audit and audit-related assurance services	**47**	47	47
Taxation compliance services	**1**	1	1
Taxation advisory services		1	1
Services relating to corporate finance transactions	**1**	1	2

Total non-audit and other assurance services	**1**	2	1
Total non-audit or non-audit-related assurance services	**3**	5	5
Services relating to BP pension plans[c]	**1**	1	1
	51	53	53

[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 service of $0.4 million (2014 $0.4 million and 2013 $0.2 million)
2015 includes $2 million of additional fees for 2014 and 2014 includes $2 million of additional fees for 2013.
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 $51 million (2014 $53 million and 2013 $53 million) is required to be presented as follows: audit $40 million (2014 $40 million and 2013 $39 million); other audit-related $7 million (2014 $7 million and 2013 $8 million); tax $1 million (2014 $2 million and 2013 $2 million); and all other fees $3 million (2014 $4 million and 2013 $4 million).

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36. Subsidiaries, joint arrangements and associates

The more important subsidiaries and associates of the group at 31 December 2015 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 undertakings of the group is included in Note 15 in the parent company financial statements of BP p.l.c. which are filed with the Registrar of Companies in the UK, along with the group s annual report.

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
BP Exploration (Azerbaijan)	100	England & Wales	Exploration and production
Canada			
*BP Holdings Canada	100	England & Wales	Investment holding
Egypt			
BP Exploration (Delta)	100	England & Wales	Exploration and production
Germany			
BP Europa SE	100	England & Wales	Refining and marketing
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
Trinidad & Tobago			
BP Trinidad and Tobago	70	US	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	
BP Company North America	100	US	Exploration and production, refining and marketing
BP Corporation North America	100	US	pipelines and petrochemicals
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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37. 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. Non-current assets for BP p.l.c. includes 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. incorporates subsidiaries of BP Exploration (Alaska) Inc. using the equity method of accounting 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					**2015**
	Issuer BP Exploration (Alaska) Inc.	**Guarantor BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Sales and other operating revenues	**3,438**		**222,881**	**(3,425)**	**222,894**
Earnings from joint ventures after interest and tax			**(28)**		**(28)**
Earnings from associates after interest and tax			**1,839**		**1,839**
Equity-accounted income of subsidiaries after interest and tax		**(5,404)**		**5,404**	
Interest and other income	**29**	**185**	**671**	**(274)**	**611**
Gains on sale of businesses and fixed assets		**31**	**666**	**(31)**	**666**
Total revenues and other income	**3,467**	**(5,188)**	**226,029**	**1,674**	**225,982**
Purchases	**1,432**		**166,783**	**(3,425)**	**164,790**
Production and manufacturing expenses	**1,360**		**35,680**		**37,040**
Production and similar taxes	**140**		**896**		**1,036**
Depreciation, depletion and amortization	**569**		**14,650**		**15,219**
Impairment and losses on sale of businesses and fixed assets	**215**		**1,694**		**1,909**
Exploration expense			**2,353**		**2,353**
Distribution and administration expenses	**56**	**1,125**	**10,449**	**(77)**	**11,553**
Profit (loss) before interest and taxation	**(305)**	**(6,313)**	**(6,476)**	**5,176**	**(7,918)**
Finance costs	**35**	**36**	**1,473**	**(197)**	**1,347**

Net finance (income) expense relating to pensions and other post-retirement benefits		**20**	**286**		**306**
Profit (loss) before taxation	**(340)**	**(6,369)**	**(8,235)**	**5,373**	**(9,571)**
Taxation	**(146)**	**82**	**(3,107)**		**(3,171)**
Profit (loss) for the year	**(194)**	**(6,451)**	**(5,128)**	**5,373**	**(6,400)**
Attributable to					
BP shareholders	**(194)**	**(6,451)**	**(5,210)**	**5,373**	**(6,482)**
Non-controlling interests			**82**		**82**
	(194)	**(6,451)**	**(5,128)**	**5,373**	**(6,400)**

Statement of comprehensive income

					$ million
For the year ended 31 December					**2015**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Profit (loss) for the year	**(194)**	**(6,451)**	**(5,128)**	**5,373**	**(6,400)**
Other comprehensive income		**1,863**	**(3,681)**		**(1,818)**
Equity-accounted other comprehensive income of subsidiaries		**(3,640)**		**3,640**	
Total comprehensive income	**(194)**	**(8,228)**	**(8,809)**	**9,013**	**(8,218)**
Attributable to					
BP shareholders	**(194)**	**(8,228)**	**(8,850)**	**9,013**	**(8,259)**
Non-controlling interests			**41**		**41**
	(194)	**(8,228)**	**(8,809)**	**9,013**	**(8,218)**

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37. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

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
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	11,364	(75)	12,266
Profit (loss) 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 (loss) before taxation	737	3,822	4,922	(4,531)	4,950
Taxation	279	42	626		947
Profit (loss) 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 continued

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
Profit (loss) 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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37. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

$ million

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	2013 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	11,269		12,611
Profit (loss) 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 (loss) before taxation	1,362	23,453	30,099	(24,693)	30,221
Taxation	522	2	5,939		6,463
Profit (loss) 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	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	2013 BP group
Profit (loss) 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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37. 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	2015 BP group
Non-current assets					
Property, plant and equipment	8,306		121,452		129,758
Goodwill			11,627		11,627
Intangible assets	539		18,121		18,660
Investments in joint ventures			8,412		8,412
Investments in associates		2	9,420		9,422
Other investments			1,002		1,002
Subsidiaries equity-accounted basis		128,234		(128,234)	
Fixed assets	8,845	128,236	170,034	(128,234)	178,881
Loans	3		7,245	(6,719)	529
Trade and other receivables			2,216		2,216
Derivative financial instruments			4,409		4,409
Prepayments	4		999		1,003
Deferred tax assets			1,545		1,545
Defined benefit pension plan surpluses		2,516	131		2,647
	8,852	130,752	186,579	(134,953)	191,230
Current assets					
Loans			272		272
Inventories	246		13,896		14,142
Trade and other receivables	9,718	1,062	22,393	(10,850)	22,323
Derivative financial instruments			4,242		4,242
Prepayments	7		1,831		1,838
Current tax receivable			599		599
Other investments			219		219
Cash and cash equivalents			26,389		26,389
	9,971	1,062	69,841	(10,850)	70,024
Assets classified as held for sale			578		578
	9,971	1,062	70,419	(10,850)	70,602
Total assets	18,823	131,814	256,998	(145,803)	261,832
Current liabilities					
Trade and other payables	961	127	41,711	(10,850)	31,949
Derivative financial instruments			3,239		3,239

Accruals	**116**	**81**	**6,064**		**6,261**
Finance debt			**6,944**		**6,944**
Current tax payable	**(21)**	**4**	**1,097**		**1,080**
Provisions	**1**		**5,153**		**5,154**
	1,057	**212**	**64,208**	**(10,850)**	**54,627**
Liabilities directly associated with assets classified as held for sale			**97**		**97**
	1,057	**212**	**64,305**	**(10,850)**	**54,724**
Non-current liabilities					
Other payables	**8**	**6,708**	**2,913**	**(6,719)**	**2,910**
Derivative financial instruments			**4,283**		**4,283**
Accruals		**33**	**857**		**890**
Finance debt			**46,224**		**46,224**
Deferred tax liabilities	**1,238**	**877**	**7,484**		**9,599**
Provisions	**2,326**		**33,634**		**35,960**
Defined benefit pension plan and other post-retirement benefit plan deficits		**227**	**8,628**		**8,855**
	3,572	**7,845**	**104,023**	**(6,719)**	**108,721**
Total liabilities	**4,629**	**8,057**	**168,328**	**(17,569)**	**163,445**
Net assets	**14,194**	**123,757**	**88,670**	**(128,234)**	**98,387**
Equity					
BP shareholders equity	**14,194**	**123,757**	**87,499**	**(128,234)**	**97,216**
Non-controlling interests			**1,171**		**1,171**
	14,194	**123,757**	**88,670**	**(128,234)**	**98,387**

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37. Condensed consolidating information on certain US subsidiaries continued

Balance sheet continued

					$ million
At 31 December					2014
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.[a]	Other subsidiaries	Eliminations and reclassifications	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	168	56,644	(17,599)	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	559	79,287	(17,599)	63,615
Non-current liabilities					
Other payables	16	6,871	3,594	(6,894)	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	7,560	104,159	(6,894)	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

[a] For 2014 BP p.l.c. comparative balances there has been a reclassification from amounts due within one year to amounts due after one year.

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37. 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	$ million 2015 BP group
Net cash provided by operating activities	**925**	**6,628**	**11,580**	**19,133**
Net cash provided by (used in) investing activities	**(925)**		**(16,375)**	**(17,300)**
Net cash provided by (used in) financing activities		**(6,659)**	**2,124**	**(4,535)**
Currency translation differences relating to cash and cash equivalents			**(672)**	**(672)**
Increase (decrease) in cash and cash equivalents		**(31)**	**(3,343)**	**(3,374)**
Cash and cash equivalents at beginning of year		**31**	**29,732**	**29,763**
Cash and cash equivalents at end of year			**26,389**	**26,389**

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.[a]	Other subsidiaries	$ million 2014 BP group
Net cash provided by operating activities	92	10,464	22,198	32,754
Net cash provided by (used in) investing activities	(92)		(19,482)	(19,574)
Net cash provided by (used in) financing activities		(10,439)	5,173	(5,266)
Currency translation differences relating to cash and cash equivalents			(671)	(671)
Increase (decrease) 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	Guarantor		$ million 2013

	BP Exploration (Alaska) Inc.	BP p.l.c.[a]	Other subsidiaries	BP group
Net cash provided by operating activities	746	10,796	9,558	21,100
Net cash provided by (used in) investing activities	(746)		(7,109)	(7,855)
Net cash provided by (used in) financing activities		(10,799)	399	(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

[a] For 2014 and 2013 BP p.l.c. comparative information certain adjustments have been made to the amounts reported for operating, investing and financing activities, with no overall impact on net cash flow.

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 227-232.

[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	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		2015
Subsidiaries										
Capitalized costs at 31 December[a b]										
Gross capitalized costs										
Proved properties	**33,214**	**10,568**	**80,716**	**3,559**	**11,051**	**42,807**		**28,474**	**5,177**	**215,566**
Unproved properties	**437**	**168**	**5,602**	**2,377**	**2,964**	**4,635**		**2,740**	**933**	**19,856**
	33,651	**10,736**	**86,318**	**5,936**	**14,015**	**47,442**		**31,214**	**6,110**	**235,422**
Accumulated depreciation	**21,447**	**7,172**	**43,290**	**191**	**6,251**	**29,406**		**15,967**	**2,677**	**126,401**
Net capitalized costs	**12,204**	**3,564**	**43,028**	**5,745**	**7,764**	**18,036**		**15,247**	**3,433**	**109,021**
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	**17**		**131**			**259**				**407**
Unproved			**56**		**(118)**	**8**				**(54)**
	17		**187**		**(118)**	**267**				**353**
Exploration and appraisal costs[c]	**178**	**11**	**651**	**75**	**114**	**533**	**5**	**102**	**125**	**1,794**
Development	**1,784**	**73**	**3,662**	**324**	**1,299**	**2,749**		**3,439**	**128**	**13,458**
Total costs	**1,979**	**84**	**4,500**	**399**	**1,295**	**3,549**	**5**	**3,541**	**253**	**15,605**
Results of operations for the year ended 31 December[a]										

Sales and other operating revenues[d]										
Third parties	**496**	**209**	**651**	**14**	**1,594**	**1,829**		**800**	**1,450**	**7,043**
Sales between businesses	**1,149**	**718**	**7,427**	**2**	**33**	**4,005**		**4,028**	**340**	**17,702**
	1,645	**927**	**8,078**	**16**	**1,627**	**5,834**		**4,828**	**1,790**	**24,745**
Exploration expenditure	**115**	**8**	**960**	**108**	**51**	**1,001**	**5**	**53**	**52**	**2,353**
Production costs	**879**	**313**	**2,777**	**77**	**703**	**1,521**		**1,083**	**166**	**7,519**
Production taxes	**(273)**		**215**		**214**			**834**	**46**	**1,036**
Other costs (income)[e]	**(795)**	**92**	**2,460**	**48**	**140**	**358**	**27**	**76**	**215**	**2,621**
Depreciation, depletion and amortization	**949**	**544**	**3,671**	**13**	**673**	**3,412**		**2,420**	**322**	**12,004**
Net impairments and (gains) losses on sale of businesses and fixed assets	**(390)**	**17**	**340**		**101**	**846**		**105**	**140**	**1,159**
	485	**974**	**10,423**	**246**	**1,882**	**7,138**	**32**	**4,571**	**941**	**26,692**
Profit (loss) before taxation[f]	**1,160**	**(47)**	**(2,345)**	**(230)**	**(255)**	**(1,304)**	**(32)**	**257**	**849**	**(1,947)**
Allocable taxes[g]	**(930)**	**159**	**(857)**	**(5)**	**(28)**	**694**	**(5)**	**(66)**	**472**	**(566)**
Results of operations	**2,090**	**(206)**	**(1,488)**	**(225)**	**(227)**	**(1,998)**	**(27)**	**323**	**377**	**(1,381)**

Upstream and Rosneft segments replacement cost profit before interest and tax

Exploration and production activities subsidiaries (as above)	**1,160**	**(47)**	**(2,345)**	**(230)**	**(255)**	**(1,304)**	**(32)**	**257**	**849**	**(1,947)**
Midstream and other activities subsidiaries[h]	**401**	**110**	**43**	**10**	**211**	**(39)**	**(16)**	**67**	**14**	**801**
Equity-accounted entities[i]		**(7)**	**19**		**370**	**(552)**	**1,326**	**363**		**1,519**
Total replacement cost profit before interest and tax	**1,561**	**56**	**(2,283)**	**(220)**	**326**	**(1,895)**	**1,278**	**687**	**863**	**373**

[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. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations 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 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 $120 million. The UK region includes a $832 million gain which is offset by corresponding charges, primarily in the US region, relating to the group self-insurance programme.

[f] Excludes the unwinding of the discount on provisions and payables amounting to $164 million which is included in finance costs in the group income statement.

[g] UK region includes the one-off deferred tax impact of the enactment of legislation to reduce the UK supplementary charge tax rate applicable to profits arising in the North Sea from 32% to 20%.

[h] Midstream and other activities excludes inventory holding gains and losses.

[i] BP s share of the profits of equity-accounted entities are included after interest and tax reported by those entities.

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Oil and natural gas exploration and production activities continued

										$ million 2015
	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)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties					**9,824**		**12,728**	**3,486**		**26,038**
Unproved properties							**437**	**26**		**463**
					9,824		**13,165**	**3,512**		**26,501**
Accumulated depreciation					**4,117**		**2,788**	**3,458**		**10,363**
Net capitalized costs					**5,707**		**10,377**	**54**		**16,138**
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved							**16**			**16**
Unproved							**26**			**26**
							42			**42**
Exploration and appraisal costs[d]					**8**		**123**	**1**		**132**
Development					**1,128**		**1,702**	**443**		**3,273**
Total costs					**1,136**		**1,867**	**444**		**3,447**
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties					**2,060**			**1,022**		**3,082**
Sales between businesses							**8,592**	**19**		**8,611**
					2,060		**8,592**	**1,041**		**11,693**
Exploration expenditure					**3**		**52**			**55**
Production costs					**647**		**1,083**	**168**		**1,898**

Production taxes			**425**		**3,911**	**388**	**4,724**
Other costs (income)			**(381)**		**284**		**(97)**
Depreciation, depletion and amortization			**465**		**992**	**484**	**1,941**
Net impairments and losses on sale of businesses and fixed assets			**80**			**35**	**115**
			1,239		**6,322**	**1,075**	**8,636**
Profit (loss) before taxation			**821**		**2,270**	**(34)**	**3,057**
Allocable taxes			**504**		**449**	**1**	**954**
Results of operations			**317**		**1,821**	**(35)**	**2,103**

Upstream and Rosneft segments replacement cost profit before interest and tax from equity-accounted entities

Exploration and production activities equity-accounted entities after tax (as above)			**317**		**1,821**	**(35)**	**2,103**
Midstream and other activities after tax[g]	**(7)**	**19**	**53**	**(552)**	**(495)**	**398**	**(584)**
Total replacement cost profit after interest and tax	**(7)**	**19**	**370**	**(552)**	**1,326**	**363**	**1,519**

[a] Amounts reported for Russia 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. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations 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] 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.

[f] Presented net of transportation costs and sales taxes.

[g] Includes interest and adjustment for non-controlling interests. Excludes inventory holding gains and losses.

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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	Rest of Asia		
Subsidiaries										
Capitalized costs at 31 December[a 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[a 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[a d]										
Sales and other operating revenues[e]										

Third parties	529	77	1,218	4	2,802	2,536		1,135	2,574	10,875
Sales between businesses	1,069	1,662	14,894	15	450	6,289		6,951	624	31,954
	1,598	1,739	16,112	19	3,252	8,825		8,086	3,198	42,829
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)[f]	(1,515)	77	3,260	55	284	120	57	(69)	343	2,612
Depreciation, depletion and amortization	506	676	3,805	4	678	3,343		2,461	255	11,728
Net 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	983	36,034
Profit (loss) before taxation[g]	(769)	(1,775)	3,599	(137)	819	1,832	(57)	1,068	2,215	6,795
Allocable taxes	(1,383)	(1,108)	1,269	15	865	1,216	3	67	1,161	2,105
Results of operations	614	(667)	2,330	(152)	(46)	616	(60)	1,001	1,054	4,690

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	2,215	6,795
Midstream and other activities subsidiaries[h]	163	99	703	130	175	(170)	(26)	(63)	14	1,025
Equity-accounted entities[i]		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. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations 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] Amendments have been made to previously published amounts for the Australasia region with no overall effect on total replacement cost profit before interest and tax.

[e] Presented net of transportation costs, purchases and sales taxes.

[f] Includes property taxes, other government take and the fair value gain on embedded derivatives of $430 million. The UK region includes a $1,016 million gain which is offset by corresponding charges, primarily in the US region, relating to the group self-insurance programme.

[g] 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.

[h] Midstream and other activities excludes inventory holding gains and losses.

[i] BP s share of the profits of equity-accounted entities are included after interest and tax reported by those entities.

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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)										
Capitalized costs at 31 December[b 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[b c]										
Acquisition of properties[d]										
Proved							(46)			(46)
Unproved							87			87
							41			41
Exploration and appraisal costs[e]					5		128	4		137
Development[f]					1,026		1,913	326		3,265
Total costs					1,031		2,082	330		3,443
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[g]										
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
Net 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
Upstream and Rosneft segments replacement cost profit before interest and tax from equity-accounted entities							
Exploration and production activities equity-accounted entities after tax (as above)			379		1,930	31	2,340
Midstream and other activities after tax[h]	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 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. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations 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] 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.

[d] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

[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] An amendment has been made to the amount previously disclosed for the Rest of Asia region.

[g] Presented net of transportation costs and sales taxes.

[h] Includes interest and adjustment for non-controlling interests. Excludes inventory holding gains and losses.

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Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Capitalized costs at 31 December[a 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[a 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[d]										
Sales and other operating revenues[e]										

Third parties	1,129	183	934	5	2,413	3,195		1,005	2,466	11,330
Sales between businesses	1,661	1,280	14,047	12	1,154	6,518		11,432	639	36,743
	2,790	1,463	14,981	17	3,567	9,713		12,437	3,105	48,073
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)[f]	(1,731)	86	3,241	55	322	89	65	84	394	2,605
Depreciation, depletion and amortization	504	490	3,268		559	3,132		2,174	207	10,334
Net 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	1,191	32,910
Profit (loss) before taxation[g]	2,552	425	3,312	(108)	4	4,453	(65)	2,676	1,914	15,163
Allocable taxes	554	475	1,204	(26)	642	1,925	(2)	682	845	6,299
Results of operations	1,998	(50)	2,108	(82)	(638)	2,528	(63)	1,994	1,069	8,864

Upstream, Rosneft and TNK-BP segments replacement cost profit before interest and tax[d]

Exploration and production activities subsidiaries (as above)	2,552	425	3,312	(108)	4	4,453	(65)	2,676	1,914	15,163
Midstream and other activities subsidiaries[h]	244	(40)	296	(14)	153	(154)	(4)	(29)	10	462
TNK-BP gain on sale							12,500			12,500
Equity-accounted entities[i]		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. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations 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] Amendments have been made to previously published amounts for the Australasia region with no overall effect on total replacement cost before interest and tax.

[e] Presented net of transportation costs, purchases and sales taxes.

[f] Includes property taxes, other government take and the fair value gain on embedded derivatives of $459 million. The UK region includes a $1,055 million gain which is offset by corresponding charges, primarily in the US region, relating to the group self-insurance programme.

[g] 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.

[h] Midstream and other activities excludes inventory holding gains and losses.

[i] BP s share of the profits of equity-accounted entities are included after interest and tax reported by those entities.

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Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)										
Capitalized costs at 31 December[b 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[b c 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[f]					714		1,860	423		2,997
Total costs					722		4,466	435		5,623
Results of operations for the year ended 31 December[b f]										
Sales and other operating revenues[g]										
Third parties					2,294		435	4,591		7,320
Sales between businesses							9,679	14		9,693
					2,294		10,114	4,605		17,013
Exploration expenditure							126	1		127
Production costs					586		1,177	382		2,145
Production taxes					630		4,511	3,383		8,524
Other costs (income)					6		94			100

Depreciation, depletion and amortization			317		1,232	648	2,197
Net impairments and losses on sale of businesses and fixed assets					37		37
			1,539		7,177	4,414	13,130
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

Upstream, Rosneft and TNK-BP segments replacement cost profit before interest and tax from equity-accounted entities

Exploration and production activities equity-accounted entities after tax (as above)			295		2,570	151	3,016
Midstream and other activities after tax[h]	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 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. Amounts relating to the management and ownership of crude oil and natural gas pipelines, LNG liquefaction and transportation operations 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] Amendments have been made to previously published numbers for the Rest of Asia region. The amendments have no overall effect on results of operations.

[g] Presented net of transportation costs and sales taxes.

[h] Includes interest and adjustment for non-controlling interests. 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	2015 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	159	95	1,030	9	10	317		384	40	2,044
Undeveloped	329	22	664	163	22	120		197	19	1,538
	488	117	1,694	172	32	437		581	59	3,582
Changes attributable to										
Revisions of previous estimates	(23)	2	(130)	39	(2)	80		295	(2)	260
Improved recovery			15			2				18
Purchases of reserves-in-place	1					6				7
Discoveries and extensions			3	42		2				47
Production[d]	(27)	(14)	(115)	(1)	(5)	(98)		(87)	(6)	(353)
Sales of reserves-in-place	(1)									(1)
	(48)	(12)	(227)	80	(6)	(8)		208	(8)	(21)
At 31 December[e]										
Developed	141	86	890	46	8	340		598	35	2,146
Undeveloped	298	19	577	205	18	89		192	16	1,414
	440	106	1,467	252	26	429		790	51	3,560
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed					316	2	2,997	89		3,405
Undeveloped					314		1,933	11		2,258
				1	630	2	4,930	101		5,663
Changes attributable to										
Revisions of previous estimates					9		(23)	3		(11)
Improved recovery					3					3
Purchases of reserves-in-place							28			28
Discoveries and extensions					9		185			194
Production					(28)		(295)	(35)		(358)
Sales of reserves-in-place							(1)			(1)
					(8)		(105)	(32)		(146)

At 31 December[g]										
Developed					**311**	**2**	**2,844**	**68**		**3,225**
Undeveloped					**311**		**1,981**			**2,292**
					622	**2**	**4,825**	**68**		**5,517**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	**159**	**95**	**1,030**	**9**	**326**	**319**	**2,997**	**473**	**40**	**5,448**
Undeveloped	**329**	**22**	**664**	**164**	**336**	**120**	**1,933**	**208**	**19**	**3,796**
	488	**117**	**1,694**	**173**	**662**	**439**	**4,930**	**682**	**59**	**9,244**
At 31 December										
Developed	**141**	**86**	**890**	**47**	**319**	**342**	**2,844**	**666**	**35**	**5,371**
Undeveloped	**298**	**19**	**577**	**205**	**329**	**89**	**1,981**	**192**	**16**	**3,707**
	440	**106**	**1,467**	**252**	**648**	**431**	**4,825**	**858**	**51**	**9,078**

[a] Crude oil includes condensate and bitumen. 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 component parts.

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 23 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 70 million barrels of crude oil in respect of the 1.27% non-controlling interest in Rosneft, including 28 mmbbl held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 4,823 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 26 million barrels in Venezuela and 4,797 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	2015 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	6	13	323		11	5			6	364
Undeveloped	3	1	104		28	7			3	146
	9	14	427		39	12			10	510
Changes attributable to										
Revisions of previous estimates	2		(80)			6			3	(69)
Improved recovery			12							12
Purchases of reserves-in-place			3							4
Discoveries and extensions										
Production[c]	(2)	(2)	(23)		(4)	(3)			(1)	(34)
Sales of reserves-in-place			(1)							(1)
		(2)	(88)		(4)	3			2	(88)
At 31 December[d]										
Developed	5	11	269		7	5			9	308
Undeveloped	4	1	70		28	10			2	115
	10	12	339		35	15			12	422
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed						15	30			46
Undeveloped							16			16
						15	46			62
Changes attributable to										
Revisions of previous estimates						(3)	1			(2)
Improved recovery										
Purchases of reserves-in-place										
Discoveries and extensions										
Production										

Sales of reserves-in-place								
					(3)	1		(2)
At 31 December[f]								
Developed					13	32		45
Undeveloped						15		15
					13	47		60
Total subsidiaries and equity-accounted entities (BP share)								
At 1 January								
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
At 31 December								
Developed	5	11	269	7	18	32	9	352
Undeveloped	4	1	70	28	10	15	2	130
	10	12	339	35	28	47	12	482

[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 component parts.

[c] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 4 thousand barrels per day for equity-accounted entities.

[d] Includes 11 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 47 million barrels in Russia.

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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	2015 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	(20)	2	(210)	39	(2)	86		295	1	191
Improved recovery			28			2				30
Purchases of reserves-in-place	1		3			6				11
Discoveries and extensions			4	42		2				48
Production[d]	(29)	(16)	(138)	(1)	(8)	(101)		(87)	(7)	(387)
Sales of reserves-in-place	(1)		(1)							(2)
	(48)	(14)	(315)	80	(10)	(5)		208	(6)	(109)
At 31 December[e]										
Developed	147	98	1,159	46	15	346		598	45	2,453
Undeveloped	302	20	647	205	46	99		192	18	1,529
	449	117	1,806	252	61	444		790	63	3,982
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed					316	17	3,028	89		3,451
Undeveloped					314		1,949	11		2,274
				1	630	17	4,976	101		5,725
Changes attributable to										
Revisions of previous estimates					9	(3)	(22)	3		(13)
Improved recovery					3					3
Purchases of reserves-in-place							28			28
Discoveries and extensions					9		185			194
Production					(28)		(295)	(35)		(358)

Sales of reserves-in-place							(1)			(1)
				(1)	(8)	(3)	(104)	(32)		(147)
At 31 December[g h]										
Developed					311	14	2,876	68		3,270
Undeveloped					312		1,996			2,307
					622	14	4,872	68		5,577
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	147	98	1,159	47	326	360	2,876	666	45	5,723
Undeveloped	302	20	647	205	357	99	1,996	192	18	3,836
	449	117	1,806	252	684	459	4,872	858	63	9,560

[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 component parts.

[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 23 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 4 thousand barrels per day for equity-accounted entities.

[e] Also includes 19 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 70 million barrels in respect of the non-controlling interest in Rosneft, including 28 mmboe held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

[h] Total proved liquid reserves held as part of our equity interest in Rosneft is 4,871 million barrels, comprising less than 1 million barrels in Canada, 26 million barrels in Venezuela, less than 1 million barrels in Vietnam and 4,844 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	2015 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	(12)	14	(1,120)	(13)	132	203		(165)	13	(948)
Improved recovery	4		432			7				443
Purchases of reserves-in-place			65		29	554				648
Discoveries and extensions			5			174				179
Production[c]	(65)	(44)	(628)	(4)	(709)	(248)		(157)	(297)	(2,151)
Sales of reserves-in-place	(5)		(6)		(58)	(35)				(104)
	(77)	(30)	(1,252)	(17)	(605)	654		(322)	(284)	(1,933)
At 31 December[d]										
Developed	348	274	6,257		2,071	847		1,803	3,408	15,009
Undeveloped	343	14	2,105		5,989	2,305		3,455	1,343	15,553
	691	288	8,363		8,060	3,152		5,257	4,751	30,563
Equity-accounted entities (BP share)[e]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates				(1)	81	(14)	1,604	(2)		1,669
Improved recovery					8					8
							5			5

Purchases of reserves-in-place										
Discoveries and extensions					209		175			384
Production[c]					(182)		(430)	(19)		(632)
Sales of reserves-in-place					(1)					(1)
				(1)	116	(14)	1,354	(21)		1,434
At 31 December[f g]										
Developed				1	1,463	386	4,962	44		6,856
Undeveloped					598		6,176	4		6,778
				1	2,061	386	11,139	48		13,634
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	348	274	6,257	1	3,534	1,233	4,962	1,847	3,408	21,865
Undeveloped	343	14	2,105		6,587	2,305	6,176	3,459	1,343	22,331
	691	288	8,363	1	10,121	3,538	11,139	5,305	4,751	44,197

[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 component parts.

[c] Includes 175 billion cubic feet of natural gas consumed in operations, 146 billion cubic feet in subsidiaries, 29 billion cubic feet in equity-accounted entities.

[d] Includes 2,359 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 129 billion cubic feet of natural gas in respect of the 0.23% non-controlling interest in Rosneft including 5 billion cubic feet held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

[g] Total proved gas reserves held as part of our equity interest in Rosneft is 11,169 billion cubic feet, comprising 1 billion cubic feet in Canada, 13 billion cubic feet in Venezuela, 22 billion cubic feet in Vietnam and 11,133 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	2015 Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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	9,695
Changes attributable to										
Revisions of previous estimates	(22)	4	(403)	36	21	121		267	4	27
Improved recovery	1		102			3				106
Purchases of reserves-in-place	1		15		5	102				122
Discoveries and extensions			4	42		32				79
Production[e f]	(40)	(23)	(247)	(2)	(130)	(144)		(114)	(58)	(758)
Sales of reserves-in-place	(1)		(2)		(10)	(6)				(19)
	(62)	(19)	(531)	77	(114)	108		153	(55)	(443)
At 31 December[g]										
Developed	207	145	2,238	46	373	492		909	632	5,041
Undeveloped	362	22	1,010	205	1,078	496		788	250	4,211
	568	167	3,248	252	1,451	988		1,696	882	9,252
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed					528	86	3,834	100		4,548
Undeveloped				1	438		2,830	13		3,280
				1	965	86	6,663	112		7,828
Changes attributable to										
Revisions of previous estimates				(1)	23	(5)	255	3		274
Improved recovery					5					5
Purchases of reserves-in-place							29			29

Discoveries and extensions					45		215			260
Production[f]					(60)		(369)	(39)		(467)
Sales of reserves-in-place							(1)			(1)
				(1)	12	(5)	129	(36)		100
At 31 December[i j]										
Developed					563	81	3,732	76		4,452
Undeveloped					415		3,061	1		3,476
					978	81	6,792	77		7,928
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	207	145	2,238	47	936	573	3,732	984	632	9,493
Undeveloped	362	22	1,010	205	1,493	496	3,061	788	250	7,687
	568	167	3,248	252	2,429	1,069	6,792	1,773	882	17,180

[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 component parts.

[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 23 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 4 thousand barrels per day for equity-accounted entities.

[f] Includes 30 million barrels of oil equivalent of natural gas consumed in operations, 25 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities.

[g] Includes 425 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 70 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 28 mmboe held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

[j] Total proved reserves held as part of our equity interest in Rosneft is 6,796 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada, 28 million barrels of oil equivalent in Venezuela, 4 million barrels of oil equivalent in Vietnam and 6,764 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	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	188	17	180		202	19	1,785
	534	200	1,760	188	31	495		522	69	3,798
Changes attributable to										
Revisions of previous estimates	(41)	(68)	87	(16)	9	20		96	(2)	85
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)	(16)	1	(58)		59	(9)	(217)
At 31 December[e]										
Developed	159	95	1,030	9	10	317		384	40	2,044
Undeveloped	329	22	664	163	22	120		197	19	1,538
	488	117	1,694	172	32	437		581	59	3,581
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	189	331	182	1,858	209	19	3,965
	534	200	1,760	189	661	499	4,828	649	69	9,388
At 31 December										
Developed	159	95	1,030	9	326	319	2,997	473	40	5,448
Undeveloped	329	22	664	164	336	120	1,933	208	19	3,796
	488	117	1,694	173	662	439	4,930	682	59	9,244

[a] Crude oil includes condensate and bitumen. 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 component parts.

[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 component parts.

[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

Total liquids[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	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 component parts.

[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										

Discoveries and extensions					69		183			252
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 component parts.

[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 equivale

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 component parts.

[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]										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	228	153	1,127		16	306		268	45	2,143
Undeveloped	426	73	818	195	20	236		137	34	1,938
	654	226	1,945	195	36	542		405	79	4,081
Changes attributable to										
Revisions of previous estimates	(79)	(15)	(111)	(7)	1	30		65	(5)	(121)
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)	(7)	(5)	(47)		117	(10)	(283)
At 31 December[d]										
Developed	160	147	1,007		15	316		320	49	2,013
Undeveloped	374	53	752	188	17	180		202	19	1,785
	534	200	1,760	188	31	495		522	69	3,798
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	195	367	239	1,943	150	34	4,243
	654	226	1,945	195	719	547	4,376	616	79	9,357
At 31 December										
Developed	160	147	1,007		331	317	2,970	440	49	5,421
Undeveloped	374	53	752	189	331	182	1,858	209	19	3,965
	534	200	1,760	189	661	499	4,828	649	69	9,388

[a] Crude oil includes condensate and bitumen. 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 component parts.

[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]	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	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 component parts.

[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

Total liquids[a] [b]	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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 component parts.

[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

Discoveries and extensions					51		254			305
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 component parts.

[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
					36		6,108	6		6,150

Purchases of reserves-in-place										
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 component parts.

[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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Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves

The following tables set out the standardized measure of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group s estimated proved reserves. This information is prepared in compliance with FASB Oil and Gas Disclosures requirements.

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of average crude oil and natural gas prices and exchange rates from the previous 12 months. Furthermore, both proved reserves estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. BP cautions against relying on the information presented because of the highly arbitrary nature of the assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

$ million

										2015
	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]	**27,500**	**7,800**	**98,100**	**7,200**	**20,100**	**32,800**		**65,200**	**32,000**	**290,700**
Future production cost[b]	**15,700**	**5,300**	**56,300**	**4,200**	**8,600**	**12,000**		**35,900**	**15,200**	**153,200**
Future development cost[b]	**4,700**	**700**	**18,800**	**1,700**	**7,000**	**8,100**		**18,200**	**4,500**	**63,700**
Future taxation[c]	**2,900**	**800**	**3,100**		**1,700**	**3,300**		**3,800**	**4,000**	**19,600**
Future net cash flows	**4,200**	**1,000**	**19,900**	**1,300**	**2,800**	**9,400**		**7,300**	**8,300**	**54,200**
10% annual discount[d]	**1,900**	**300**	**7,400**	**900**	**900**	**4,300**		**3,700**	**4,400**	**23,800**
Standardized measure of discounted future net cash flows[e]	**2,300**	**700**	**12,500**	**400**	**1,900**	**5,100**		**3,600**	**3,900**	**30,400**
Equity-accounted entities (BP share)[f]										

Future cash inflows[a]					**39,900**		**182,300**	**3,700**		**225,900**
Future production cost[b]					**20,200**		**101,200**	**2,200**		**123,600**
Future development cost[b]					**5,300**		**11,000**	**1,300**		**17,600**
Future taxation[c]					**3,900**		**12,400**	**100**		**16,400**
Future net cash flows					**10,500**		**57,700**	**100**		**68,300**
10% annual discount[d]					**6,700**		**33,800**			**40,500**
Standardized measure of discounted future net cash flows[g h]					**3,800**		**23,900**	**100**		**27,800**
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	**2,300**	**700**	**12,500**	**400**	**5,700**	**5,100**	**23,900**	**3,700**	**3,900**	**58,200**

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	**(27,900)**	**(7,300)**	**(35,200)**
Development costs for the current year as estimated in previous year	**15,000**	**4,500**	**19,500**
Extensions, discoveries and improved recovery, less related costs	**600**	**700**	**1,300**
Net changes in prices and production cost	**(100,400)**	**(24,700)**	**(125,100)**
Revisions of previous reserves estimates	**13,500**	**500**	**14,000**
Net change in taxation	**38,600**	**2,300**	**40,900**
Future development costs	**3,200**	**(100)**	**3,100**
Net change in purchase and sales of reserves-in-place	**(700)**	**300**	**(400)**
Addition of 10% annual discount	**8,000**	**4,700**	**12,700**
Total change in the standardized measure during the year[i]	**(50,100)**	**(19,100)**	**(69,200)**

[a] The marker prices used were Brent $54.17/bbl, Henry Hub $2.59/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 $600 million.

[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.

[g] Non-controlling interests in Rosneft amounted to $93 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 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

2014

	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]	54,400	14,900	216,600	11,000	35,300	55,800		90,300	54,800	533,100
Future production cost[b]	21,400	8,100	90,500	4,800	11,300	15,600		41,500	17,600	210,800
Future development cost[b]	7,300	1,400	24,500	1,600	8,000	9,600		23,000	5,700	81,100
Future taxation[c]	16,400	3,000	32,900	700	8,400	10,100		5,100	9,400	86,000
Future net cash flows	9,300	2,400	68,700	3,900	7,600	20,500		20,700	22,100	155,200
10% annual discount[d]	4,700	700	33,100	2,500	3,100	7,800		11,000	11,800	74,700
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	80,500
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]					47,300		349,200	10,200		406,700
Future production cost[b]					22,300		200,000	7,800		230,100
Future development cost[b]					5,700		17,400	2,100		25,200
Future taxation[c]					6,700		24,200	100		31,000

Future net cash flows					12,600		107,600	200		120,400
10% annual discount[d]					8,000		65,500			73,500
Standardized measure of discounted future net cash flows[g h]					4,600		42,100	200		46,900
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	127,400

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

$ million

	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(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 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

	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
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
					5,900		15,200	100		21,200

Future taxation[c]										
Future net cash flows					11,400		81,700	300		93,400
10% annual discount[d]					6,900		48,700	100		55,700
Standardized measure of discounted future net cash flows[g h]					4,500		33,000	200		37,700
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	7,100	2,900	36,500	500	10,000	15,200	33,000	11,000	9,800	126,000

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

			$ million
	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(30,600)	(7,900)	(38,500)
Development costs for the current year as estimated in previous year	14,000	3,200	17,200
Extensions, discoveries and improved recovery, less related costs	1,900	2,000	3,900
Net changes in prices and production cost	(1,800)	(100)	(1,900)
Revisions of previous reserves estimates	(3,100)	(400)	(3,500)
Net change in taxation	12,900	3,400	16,300
Future development costs	(4,100)	(2,100)	(6,200)
Net change in purchase and sales of reserves-in-place	(3,500)	9,000	5,500
Addition of 10% annual discount	9,300	2,800	12,100
Total change in the standardized measure during the year[i]	(5,000)	9,900	4,900

[a] The marker prices used were Brent $108.02/bbl, Henry Hub $3.66/mmBtu.

[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.

[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.

[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.

[e] Non-controlling 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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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 2015, 2014 and 2013.

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
2015	**72**	**38**	**323**	**3**	**12**	**270**		**237**	**17**	**971**
2014	46	41	347		13	222		156	19	844
2013	58	31	305		17	217		141	21	789
Natural gas liquids										thousand barrels per day
2015	**7**	**5**	**56**		**11**	**7**		**1**	**3**	**88**
2014	2	5	63		12	5			3	91
2013	3	4	58		12	3		1	4	86
Natural gas[e]										million cubic feet per day
2015	**155**	**111**	**1,528**	**10**	**1,922**	**589**		**380**	**801**	**5,495**
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
Equity-accounted entities (BP share)										
Crude oil[d]										thousand barrels per day
2015					**68**		**809**	**97**		**974**
2014					65		816	98		979
2013					62		826	232		1,120
Natural gas liquids										thousand barrels per day

2015	**3**	**3**	**4**		**10**
2014	3	4	5		12
2013	3	5	11		19
Natural gas[e]					million cubic feet per day
2015	**435**		**1,195**	**21**	**1,651**
2014	402		1,084	28	1,515
2013	384		801	30	1,216

[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 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 2015. 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	T
		UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Number of productive wells at 31 December 2015											
Oil wells[c]	gross	**121**	**65**	**2,428**	**143**	**4,848**	**659**	**45,134**	**1,036**	**12**	**54**
	net	**77**	**26**	**830**	**33**	**2,680**	**457**	**8,914**	**354**	**2**	**13**
Gas wells[d]	gross	**63**	**5**	**22,760**	**309**	**821**	**144**	**791**	**860**	**73**	**25**
	net	**27**	**1**	**9,492**	**153**	**303**	**62**	**156**	**320**	**14**	**10**
Oil and natural gas acreage at 31 December 2015										thousands of	
Developed	gross	**128**	**40**	**6,226**	**237**	**1,386**	**655**	**4,828**	**866**	**194**	**14**
	net	**74**	**17**	**3,366**	**111**	**417**	**255**	**908**	**267**	**36**	**5**
Undeveloped[e]	gross	**1,500**	**1,501**	**6,662**	**9,712**	**22,046**	**32,692**	**378,688**	**7,395**	**15,661**	**475**
	net	**1,056**	**571**	**4,855**	**5,566**	**6,619**	**21,210**	**73,971**	**2,518**	**9,743**	**126**

[a] Based on information received from Rosneft as at 31 December 2015.
[b] Because of rounding some totals may not exactly agree with the sum of their component parts.
[c] Includes approximately 7,944 gross (1,582 net) multiple completion wells (more than one formation producing into the same well bore).
[d] Includes approximately 3,232 gross (1,534 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.
[e] 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[a]
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
2015										
Exploratory										
Productive			**4.0**		**1.1**	**2.6**	**4.5**			**12.2**
Dry					**0.4**	**1.0**			**0.2**	**1.6**
Development										
Productive	**1.6**	**0.4**	**235.6**		**143.1**	**20.7**	**91.4**	**51.2**	**0.9**	**544.7**
Dry					**2.3**	**1.3**				**3.5**
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

[a] Because of rounding, some totals may not exactly agree with the sum of their component parts.

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 2015. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	Europe		North America		South America	Africa	Asia		Australasia	Total[a]
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2015										
Exploratory										
Gross	**1.0**		**11.0**			**4.0**				**16.0**
Net	**0.3**		**6.6**			**1.8**				**8.6**
Development										
Gross	**2.0**		**309.0**	**14.0**	**11.0**	**40.0**		**55.0**	**3.0**	**434.0**
Net	**1.3**		**109.0**	**7.0**	**6.2**	**18.9**		**19.8**	**0.5**	**162.7**

[a] Because of rounding, some totals may not exactly agree with the sum of their component parts.

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Pages 196-213 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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Additional

disclosures

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Selected financial information

This information, insofar as it relates to 2015, has been extracted or derived from the audited consolidated financial statements of the BP group presented on page 95. 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				
	2015	2014	2013	2012	2011
Income statement data					
Sales and other operating revenues	**222,894**	353,568	379,136	375,765	375,713
Underlying replacement cost (RC) profit before interest and taxation*	**8,791**	20,818	22,776	26,454	33,601
Net favourable (unfavourable) impact of non-operating items* and fair value accounting effects*	**(14,820)**	(8,196)	9,283	(6,091)	3,580
RC profit (loss) before interest and taxation*	**(6,029)**	12,622	32,059	20,363	37,181
Inventory holding gains (losses)*	**(1,889)**	(6,210)	(290)	(594)	2,634
Profit (loss) before interest and taxation	**(7,918)**	6,412	31,769	19,769	39,815
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(1,653)**	(1,462)	(1,548)	(1,638)	(1,587)
Taxation	**3,171**	(947)	(6,463)	(6,880)	(12,619)
Profit (loss) for the year	**(6,400)**	4,003	23,758	11,251	25,609
Profit (loss) for the year attributable to BP shareholders	**(6,482)**	3,780	23,451	11,017	25,212
Inventory holding (gains) losses, net of taxation	**1,320**	4,293	230	411	(1,800)
RC profit (loss) for the year attributable to BP shareholders	**(5,162)**	8,073	23,681	11,428	23,412
Non-operating items and fair value accounting effects, net of taxation	**11,067**	4,063	(10,253)	5,643	(2,242)
Underlying RC profit for the year attributable to BP shareholders	**5,905**	12,136	13,428	17,071	21,170
Per ordinary share cents					
Profit (loss) for the year attributable to BP shareholders					
Basic	**(35.39)**	20.55	123.87	57.89	133.35
Diluted	**(35.39)**	20.42	123.12	57.50	131.74
RC profit (loss) for the year attributable to BP shareholders	**(28.18)**	43.90	125.08	60.05	123.83
Underlying RC profit for the year attributable to BP shareholders	**32.22**	66.00	70.92	89.70	111.97
Dividends paid per share cents	**40.00**	39.00	36.50	33.00	28.00
pence	**26.383**	23.850	23.399	20.852	17.404
Capital expenditure and acquisitions, on an accruals basis	**19,531**	23,781	36,612	25,204	31,959
Acquisitions and asset exchanges, on an accruals basis	**49**	420	71	200	11,283

Other inorganic capital expenditure, on an accruals basis	**734**	469	11,941	1,054	1,096
Organic capital expenditure*, on an accruals basis	**18,748**	22,892	24,600	23,950	19,580
Balance sheet data (at 31 December)					
Total assets	**261,832**	284,305	305,690	300,466	292,907
Net assets	**98,387**	112,642	130,407	119,752	112,585
Share capital	**5,049**	5,023	5,129	5,261	5,224
BP shareholders equity	**97,216**	111,441	129,302	118,546	111,568
Finance debt due after more than one year	**46,224**	45,977	40,811	38,767	35,169
Net debt to net debt plus equity*	**21.6%**	16.7%	16.2%	18.7%	20.4%
Ordinary share data[a]					Shares million
Basic weighted average number of shares	**18,324**	18,385	18,931	19,028	18,905
Diluted weighted average number of shares	**18,324**	18,497	19,046	19,158	19,136

[a] 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 included in the financial statements 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
	2015	2014	2013
Upstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**(1,204)**	(6,576)	(802)
Environmental and other provisions	**(24)**	(60)	(20)
Restructuring, integration and rationalization costs	**(410)**	(100)	
Fair value gain (loss) on embedded derivatives	**120**	430	459
Other[b c]	**(717)**	8	(1,001)
	(2,235)	(6,298)	(1,364)
Downstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**131**	(1,190)	(348)
Environmental and other provisions	**(108)**	(133)	(134)
Restructuring, integration and rationalization costs	**(607)**	(165)	(15)
Fair value gain (loss) on embedded derivatives			
Other	**(6)**	(82)	(38)
	(590)	(1,570)	(535)
TNK-BP			
Impairment and gain (loss) on sale of businesses and fixed assets			12,500
Environmental and other provisions			
Restructuring, integration and rationalization costs			
Fair value gain (loss) on embedded derivatives			
Other			
			12,500
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]	**(170)**	(304)	(196)
Environmental and other provisions	**(151)**	(180)	(241)
Restructuring, integration and rationalization costs	**(71)**	(176)	(3)
Fair value gain (loss) on embedded derivatives			
Other[c]	**(155)**	(10)	19
	(547)	(670)	(421)
Gulf of Mexico oil spill response	**(11,709)**	(781)	(430)

Total before interest and taxation	**(15,081)**	(9,094)	9,705
Finance costs[d]	**(247)**	(38)	(39)
Taxation credit[e] (charge)	**4,056**	4,512	867
Total after taxation	**(11,272)**	(4,620)	10,533

[a] See Financial statements Note 4 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.

[c] 2015 principally relates to BP s share of impairment losses recognized by equity-accounted entities.

[d] Finance costs relate to the Gulf of Mexico oil spill. See Financial statements Note 2 for further details.

[e] From 2014, tax is based on statutory rates except for non-deductible or non-taxable items. For 2013, 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).

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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 256.

$ million

	2015	2014	2013
Upstream			
Unrecognized gains (losses) brought forward from previous period	**(191)**	(160)	(404)
Unrecognized (gains) losses carried forward	**296**	191	160
Favourable (unfavourable) impact relative to management s measure of performance	**105**	31	(244)
Downstream[a]			
Unrecognized gains (losses) brought forward from previous period	**(188)**	679	501
Unrecognized (gains) losses carried forward	**344**	188	(679)
Favourable (unfavourable) impact relative to management s measure of performance	**156**	867	(178)
	261	898	(422)
Taxation credit (charge) [b]	**(56)**	(341)	142
	205	557	(280)
By region			
Upstream			
US	**(66)**	23	(269)
Non-US	**171**	8	25
	105	31	(244)
Downstream[a]			
US	**102**	914	(211)
Non-US	**54**	(47)	33
	156	867	(178)

[a] Fair value accounting effects arise solely in the fuels business.
[b] From 2014, tax is calculated using statutory rates. For 2013 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

	2015	2014	2013
Upstream			
RC profit (loss) before interest and tax adjusted for fair value accounting effects	**(1,042)**	8,903	16,901
Impact of fair value accounting effects	**105**	31	(244)

RC profit (loss) before interest and tax	**(937)**	8,934	16,657
Downstream			
RC profit before interest and tax adjusted for fair value accounting effects	**6,955**	2,871	3,097
Impact of fair value accounting effects	**156**	867	(178)
RC profit before interest and tax	**7,111**	3,738	2,919
Total group			
Profit (loss) before interest and tax adjusted for fair value accounting effects	**(8,179)**	5,514	32,191
Impact of fair value accounting effects	**261**	898	(422)
Profit (loss) before interest and tax	**(7,918)**	6,412	31,769

Operating capital employed*

	$ million
	2015
Upstream	**107,197**
Downstream	**34,935**
Rosneft	**5,797**
Other businesses and corporate	**19,399**
Gulf of Mexico oil spill response	**(18,797)**
Consolidation adjustment UPII*	**(68)**
Total operating capital employed	**148,463**
Liabilities for current and deferred taxation	**(8,535)**
Goodwill	**11,627**
Finance debt	**(53,168)**
Net assets	**98,387**

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 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. Our principal objective over the medium term is to re-establish a balance in our financial framework, where operating cash flow (excluding payments related to the Gulf of Mexico oil spill) covers capital expenditure and the dividend at an assumed medium-term price of $60 per barrel. We aim to do this while maintaining safe and reliable operations, preserving core growth activities and sustaining the dividend. We responded quickly to the lower environment, resetting both the capital and cash cost base of the Group. We expect organic capital expenditure in 2016 to be at the lower end of the range of $17-19 billion. In 2016 we expect to announce a further $3-5 billion of divestments and from 2017 we expect divestments to average the historical norm of around $2-3 billion per annum.

We aim to manage gearing* with some flexibility around the 20% level while volatile market conditions remain and maintain a significant liquidity buffer. We expect the net debt ratio to be above 20% while oil prices remain weak. As well as uncertainties relating to current lower oil prices, the group also continues to face uncertainties relating to the Gulf of Mexico oil spill as explained in Financing the group s activities below.

We will keep our financial framework under review as we monitor oil and gas prices and their impact on industry costs as we move through 2016 and beyond.

Dividends and other distributions to shareholders

Since resuming dividend payments with a quarterly dividend of 7 cents per share paid in 2011, it has increased by 43% to 10 cents per share paid in the fourth quarter of 2015. The dividend level is regularly reviewed by the board.

The total dividend paid in cash to BP shareholders in 2015 was $6.7 billion (2014 $5.9 billion) with shareholders also having the option to receive a scrip dividend. The dividend is determined in US dollars, the economic currency of BP.

Details of share repurchases to satisfy the requirements of certain employee share-based payment plans are set out on page 253. There were no other buyback programmes during 2015.

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 53 for further information on risks associated with prices and markets and Financial statements Note 28.

The group s gross debt at 31 December 2015 amounted to $53.2 billion (2014 $52.9 billion). Of the total gross debt, $6.9 billion is classified as short term at the end of 2015 (2014 $6.9 billion). See Financial statements Note 25 for more information on the short-term balance.

Standard & Poor s Ratings long-term credit rating for BP is A- and assigned a stable outlook and Moody s Investors Service rating is A2 (rating under review).

Net debt was $27.2 billion at the end of 2015 an increase of $4.6 billion from the 2014 year-end position of $22.6 billion. The ratio of net debt to net debt plus equity* was 21.6% at the end of 2015 (2014 16.7%). See Financial statements Note 26 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 $26.4 billion at 31 December 2015 (2014 $29.8 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 robust cash position.

The group also has undrawn committed bank facilities of $7.4 billion (see Financial statements Note 28 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 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 24 and Note 28. 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 25 and Note 28.

In relation to the Gulf of Mexico oil spill, during 2015, BP signed agreements in principle to settle all federal and state claims, subject to court approval, and to settle claims made by more than 400 local government entities. These agreements significantly reduce the uncertainties faced by BP following the Gulf of Mexico oil spill in 2010. There continues to be uncertainty regarding the outcome or resolution of current or future litigation and the extent and timing of costs relating to the incident not covered by these agreements. See Risk factors on page 53 and Financial statements Note 2 for further information.

Off-balance sheet arrangements

At 31 December 2015, the group s share of third-party finance debt of equity-accounted entities was $11.8 billion (2014 $14.7 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, incremental to amounts recognized on the balance sheet, at 31 December 2015 were $35 million (2014 $83 million) in respect of liabilities of joint ventures* and associates* and $163 million (2014 $244 million) in respect of liabilities of other third parties. Of these amounts, $22 million (2014 $64 million) of the joint ventures and associates guarantees relate to borrowings and for other third-party guarantees, $119 million (2014 $126 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 27.

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 246 and Risk factors on page 53, 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.

* Defined on page 256.

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Contractual obligations

The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2015 and the proportion of that expenditure for which contracts have been placed.

							$ million
							Payments due by period
Capital expenditure	Total	2016	2017	2018	2019	2020	2021 and thereafter
Committed	36,972	15,408	8,009	7,248	4,490	855	962
of which is contracted	10,379	6,224	2,031	1,317	645	75	87

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 2015, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $4,229 million. Contracts were in place for $2,933 million of this total.

The following table summarizes the group s principal contractual obligations at 31 December 2015, 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 25 and more information on operating leases is given in Financial statements Note 27.

							$ million
							Payments due by period
Expected payments by period under contractual obligations	Total	2016	2017	2018	2019	2020	2021 and thereafter
Balance sheet obligations							
Borrowings[a]	56,692	7,764	6,502	6,815	6,600	6,741	22,270
Finance lease future minimum lease payments[b]	1,460	108	106	97	95	91	963
Decommissioning liabilities[c]	21,762	796	600	596	383	643	18,744
Environmental liabilities[c]	10,012	586	822	480	669	664	6,791
Pensions and other post-retirement benefits[d]	23,399	1,656	1,805	1,791	1,785	1,278	15,084
	113,325	10,910	9,835	9,779	9,532	9,417	63,852
Off-balance sheet obligations							
Operating lease future minimum lease payments[e]	15,422	4,144	2,904	1,933	1,615	1,291	3,535
Unconditional purchase obligations[f]	120,286	47,859	12,489	8,743	7,540	5,594	38,061
	135,708	52,003	15,393	10,676	9,155	6,885	41,596

Total	249,033	62,913	25,228	20,455	18,687	16,302	105,448

[a] Expected payments include interest totalling $4,227 million ($866 million in 2016, $754 million in 2017, $649 million in 2018, $541 million in 2019, $432 million in 2020 and $985 million thereafter).

[b] Expected payments include interest totalling $757 million ($62 million in 2016, $58 million in 2017, $55 million in 2018, $51 million in 2019, $46 million in 2020 and $485 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 2016 include purchase commitments existing at 31 December 2015 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 28.

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

							$ million
							Payments due by period
Unconditional purchase obligations	Total	2016	2017	2018	2019	2020	2021 and thereafter
Crude oil and oil products	47,466	28,715	4,534	3,127	2,308	2,008	6,774
Natural gas	21,322	11,639	3,791	2,221	1,480	767	1,424
Chemicals and other refinery feedstocks	6,464	2,210	1,215	1,295	1,340	264	140
Power	4,918	2,558	1,031	478	292	121	438
Utilities	630	197	174	115	64	20	60
Transportation	21,138	1,190	1,008	971	960	1,291	15,718
Use of facilities and services	18,348	1,350	736	536	1,096	1,123	13,507
Total	120,286	47,859	12,489	8,743	7,540	5,594	38,061

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Upstream analysis by region

Our upstream operations are set out below by geographical area, with associated significant events for 2015. BP s percentage working interest in oil and gas assets is shown in brackets. Working interest is the cost-bearing ownership share of an oil or gas lease. Consequently, the percentages disclosed for certain agreements do not necessarily reflect the percentage interests in reserves and production.

In addition to exploration, development and production activities, our upstream business also includes midstream and LNG supply 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 markets including Japan, South Korea, China, the Dominican Republic, Argentina, Brazil and Mexico.

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.

BP and its partners, ConocoPhillips, Chevron and Shell, announced their 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 in March 2013. In March we completed the sixth and final well of the programme. The Clair field partners will review the significant amount of data collected to determine the potential for development.

The Quad 204 project, a major redevelopment to extend the life of the Schiehallion and Loyal fields to the west of Shetland, continued in 2015. After successfully completing sea trials, Glen Lyon, the replacement floating production, storage and offload vessel (FPSO), departed South Korea in December at the start of its journey to the Shetlands. We also ran a major offshore campaign focusing on the pre-installation of risers and ancillary equipment in preparation for its arrival. As well as the new FPSO, the redevelopment includes extension of the existing subsea infrastructure and drilling new wells. In April, on behalf of its co-venturers, BP announced the start of a seven-year drilling campaign on the Loyal field by the new-build, semi-submersible drilling rig, Deepsea Aberdeen.

In June BP and its partners announced that the Clair Ridge platform s topside modules for accommodation and utilities had been installed. The next major milestone will be the installation of the production and drilling platform topside modules, scheduled for summer 2016, with production expected to commence in late 2017.

In July we were awarded five new blocks across two licences in the North Sea as part of the second tranche of the 28th licensing round by the UK Oil and Gas Authority, bringing the total blocks awarded to BP to 12 to date in this licensing round.

Maersk Oil announced the UK Oil and Gas Authority s approval of development plans for the Culzean field in the UK North Sea in August. Culzean is operated by Maersk Oil on behalf of its partners, JX Nippon and BP (16%).

We completed the Magnus life extension project in July enabling Magnus to continue safe and compliant operations. This was the first project in our North Sea renewals programme, designed to extend the productive life of mature assets. Production for Magnus has been extended by five years to 2023. Additional accommodation has been constructed to enable maintenance of this ageing facility and a return to drilling in 2017.

The ETAP life extension and additional living-quarters project began in 2015 and is scheduled to run through 2016. These activities aim to delay cessation of production for the ETAP fields to 2030 by executing maintenance scope and installing additional living quarters on the central processing facility. Total investment on these projects is currently estimated at $360 million gross.

Operations at the Rhum gas field continued under a temporary management scheme announced by the UK government in 2013. Production was suspended between November 2010 and October 2014 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 242.

In December, a number of North Sea assets were subject to impairment charges totalling $830 million, primarily as a result of the lower price environment. These were however more than offset by impairment reversals of $945 million in relation to other assets in the region arising as a result of decreases in cost estimates and a reduction in the discount rate applied.

In the UK 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 2015 of 442mboe/d. BP also operated and had 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. Average throughput in 2015 was 40mboe/d. In April, BP announced the sale of its equity in the CATS business to Antin Infrastructure Partners for a headline price of $486 million, and the sale completed in December. BP also operates the Sullom Voe oil and gas terminal in Shetland.

North America

Our upstream activities in North America take place in four main areas: deepwater Gulf of Mexico, the 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 41.

BP has around 500 lease blocks in the deepwater Gulf of Mexico, making us one of the largest portfolio owners, and operates four production hubs.

We announced a new ownership and operating model with Chevron and ConocoPhillips in January 2015. We sold approximately half of our equity interests in the Gila field to Chevron in December 2014 and approximately half of our equity interest in the Tiber field to them in January 2015. BP, Chevron and ConocoPhillips also have agreed to joint ownership interests in exploration blocks east of Gila known as Gibson (BP 34%). Chevron will operate Tiber (BP 31%), Gila (BP 34%) and Gibson. Operatorship transferred at the end of 2015 after BP finished drilling appraisal wells at Gila and Tiber. These arrangements enable us to support exploration and development in the Paleogene, share development costs and maximize synergies allowing us to manage and improve capital efficiency, as well as increase our focus on maximizing production at our existing operated hubs.

In the fourth quarter, BP began drilling operations on two wells, the Chevron operated Gibson prospect and the appraisal well on the Hopkins discovery. Both wells will complete in 2016.

In March we incurred drilling rig contract cancellation costs of $375 million for two deepwater drilling rigs in the Gulf of Mexico which are no longer required for our operations.

In November BP and its partners in the Mad Dog Phase 2 project (BP 60.5%) approved a modified development plan and were awarded a Suspension of Production from the US Department of the Interior. Mad Dog Phase 2 will develop resources in the central area of the field through a subsea development consisting of up to 24 wells from four drill centres.

In December we wrote off $345 million relating to costs for the Gila discovery as these resources would be challenging to develop in the current environment.

See also Significant estimate or judgement: oil and natural gas accounting on page 109 for further information on leases.

See page 30 for further information on our Thunder Horse South Expansion project.

*Defined on page 256.

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The US Lower 48 onshore business has significant activities across six states producing natural gas, oil, NGLs and condensate. It is organized into five, geographic business units, and has a resource base that is mainly in unconventional reservoirs* (tight gas*, shale gas and coalbed methane). This resource spans 5.4 million gross developed acres (3.1 million net) and has approximately 9,000 operated gross wells, with daily net production around 280mboe/d.

Our US Lower 48 onshore business began operating as a separate business in 2015. While remaining part of our Upstream segment, it has its own governance, processes and systems and is designed to increase competitive performance through swift decision making and innovation, while maintaining BP s commitment to safe, reliable and compliant operations.

In December the US Lower 48 onshore business expanded its San Juan basin operations by acquiring all of Devon Energy s assets in the region. The bulk of the acquired assets, which span northern New Mexico and southern Colorado, consist of Devon s operated interest in the Northeast Blanco Unit.

For further information on the use of hydraulic fracturing in our shale gas assets see page 47. BP s onshore US crude oil and product pipelines and related transportation assets are included in the Downstream segment.

In Alaska BP operated nine North Slope oilfields in the Greater Prudhoe Bay area at the end of 2015. Our focus continues to be safe and reliable operations, renewing BP s Alaska North Slope infrastructure and minimizing oil production decline. Infrastructure renewal activities in 2015 included fire and gas system upgrades, safety system upgrades, pipeline renewal and facility siting projects. Production decline is being managed through annual drilling programmes and rig and non-rig well work programmes. BP also owns significant interests in six producing fields operated by others, as well as significant non-operating interests in the Point Thomson development project and the Liberty prospect.

Development of the Point Thomson production facility continued in 2015. Construction of field infrastructure and fabrication of the four main process modules is progressing on schedule. The project is on track to commence production in early 2016. BP holds a 32% working interest in the field and ExxonMobil is the operator.

BP continued to work jointly with ExxonMobil, ConocoPhillips and the State of Alaska throughout 2015 to advance the Alaska LNG project. The project concept includes a North Slope gas treatment plant, an approximately 800-mile pipeline to tidewater and a three-train liquefaction facility, with an estimated capacity of 3bcf/d (up to 20 million tonnes per annum). In 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 through 2016 with a gross spend of more than $500 million. In March, the Federal Energy Regulatory Commission issued a Notice of Intent to prepare an environmental impact statement for the Alaska LNG project. In May 2015 the US Department of Energy conditionally authorized the export of Alaska LNG to non-Free Trade Agreement countries. In October and November the co-venturers received approval from the Alaska Oil & Gas Conservation Commission for gas offtake from the Prudhoe Bay and Point Thomson fields respectively sufficient to underpin gas export. A decision point for progressing to the front-end engineering and design (FEED) phase of the project will be reached in 2017 after completion of the pre-FEED phase. First commercial gas is planned between 2023 and 2025.

In December, a number of Alaska assets were subject to impairment charges totalling $194 million, primarily as a result of the lower price environment.

BP owns a 49% interest in the Trans-Alaska Pipeline System (TAPS). 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 owners of TAPS. The transfer of Koch s interest to the remaining owners was completed in 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 2016.

In November 2015, the Federal Energy Regulatory Commission (FERC) issued an order addressing the TAPS tariff rate filings for years 2009 and
2010. The decision will result in an increase in BP s production tax and royalty liabilities to the State of Alaska, retroactively from 2009 onwards.

In Canada, BP is currently focused on oil sands development using 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, Nova Scotia and Newfoundland.

Following the start of steam generation at the Sunrise Phase 1 in-situ oil sands project in Alberta (BP 50%) in December 2014, oil production began in March. Production is expected to ramp-up to full capacity of 60,000 barrels per day (gross) in 2017.

BP completed processing seismic data acquired offshore Nova Scotia at the end of 2015. We and our partners Hess (40%) and Woodside (20%) are planning to choose potential exploration well locations in 2016 and, pending regulatory approval, begin the first exploration drilling programme.

In partnership with Statoil and ExxonMobil, BP was a successful bidder for exploration licences in the Flemish Pass Basin offshore Newfoundland. Statoil will operate all three licences, and ExxonMobil will participate in two licences as a partner. The licences have an effective date of 15 January 2016. BP has a 33% share in the NL15-01-06 and NL15-01-07 licences and a 50% share in the NL15-01-08 licence.

South America

BP has upstream activities in Brazil and Trinidad & Tobago, as well as in Argentina, Bolivia, and Chile through an equity-accounted joint venture*.

In Brazil BP has interests in 21 exploration concessions across five basins.

We continued appraisal of the Itaipu discovery, located in the deepwater sector of the Campos basin offshore Brazil in block BM-C-32, in line with the appraisal plan approved by the Brazilian National Petroleum Agency (ANP) in 2015. In October BP and its partner Anadarko submitted an application to ANP to transfer operatorship from BP to Anadarko. This will achieve significant efficiencies in progressing the development of this and an adjacent block, BM-C-30 (Wahoo), where Anadarko is the operator. Also in October, an extension request was filed with the ANP for three additional years for each of Itaipu and Wahoo to progress appraisal activities.

In May we received final approval from ANP for the previously signed agreement with Petroleo Brasileiro S.A. (Petrobras) to farm in to five deepwater exploration blocks in Potiguar basin. The blocks are located in the Brazilian equatorial margin and cover an area of 3,837km^2. The Pitu-2 well was completed during the year and proved the presence of oil.

After disappointing exploration results in October, BP and Petrobras submitted an application to ANP to relinquish their interest in BM-CE-2 block in Ceara basin.
During the year we progressed the preparatory activities for drilling exploration wells in the Foz de Amazonas and Barrerinhas blocks acquired in May 2013.
We continued discussions with the operators of blocks BM-C-35 and BC-2, Petrobras and Total respectively, to define the optimal appraisal of these blocks in the South Campos basin.

In May we notified the Uruguayan oil and gas regulator, ANCAP, that interpretation of seismic data acquired over BP-operated blocks in Uruguay had not resulted in identification of viable prospects. As a result we relinquished our 100% interest in all the blocks in Uruguay and ANCAP approved this in February 2016.

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 September 2015 PAE sold its 50% interest in the Coiron licence in Chile. In addition, PAE has acquired a 60% working interest in the Hokchi production-sharing agreement* (PSA) in Mexico, effective from January 2016.

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In Trinidad & Tobago BP holds exploration and production licences and PSAs covering 1.8 million acres offshore of the east and north-east coast. Facilities include 13 offshore platforms and two onshore processing facilities. Production comprises gas and associated liquids.

BP also has a shareholding in Atlantic LNG (ALNG), an LNG liquefication plant that averages 39% across four LNG trains* 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 LNG from 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 remaining 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.

- Development of the Juniper project continues following its sanction in 2014. The lift and cellar decks are now completed. Fabrication of the jacket and subsea structures has commenced. The first two wells have been drilled and work in preparation for drilling the remaining three is complete.

Africa

BP s upstream activities in Africa are located in Angola, Algeria, Libya, Egypt and Morocco.

In Angola BP is present in eight major deepwater licences offshore and is operator in four of these, blocks 18 and 31 that are producing oil and blocks 19 and 24 that are in the exploration phase. BP also has an equity interest in the Angola LNG plant (BP 13.6%).

- In April oil production started ahead of schedule at the Kizomba Satellites Phase-2 development in block 15 (BP 26.67%), offshore Angola. The project is a subsea infrastructure development of the Kakocha, Bavuca and Mondo South fields. Mondo South was the first to begin production, with the remaining two also starting up in 2015. This deepwater project is operated by a subsidiary of ExxonMobil.
- Our Greater Plutonio Phase 3 project, in block 18, achieved first production from the subsea well, Pu-PQ, in the Plutonio reservoir in June six months ahead of schedule. The project is a subsea tie-in to the existing Greater Plutonio FPSO in a water depth of approximately 1,300 metres. BP is the operator with a 50% interest and Sonangol Sinopec International Limited has the remaining 50% interest.
- On 21 July Total announced that they started production from Dalia Phase 1A, a new development on its offshore operated block 17 (BP 16.7%). The project involves drilling seven infill wells tied back to the Dalia FPSO.
- Katambi-1, the first pre-salt play drilled by BP in the Benguela basin in block 24 discovered hydrocarbons. Technical and commercial evaluation of this is ongoing.
- Pandora-1, the first pre-salt play drilled by BP in the Kwanza basin in block 19 also discovered hydrocarbons but will require nearby developments to be potentially commercial. Due to the uncertainty BP wrote off the costs of the well and the associated block 19 licence ($336 million) in 2015.
- The Angola LNG plant (BP 13.6%), which has been shut down for planned repairs since April 2014 is expected to fully restart in 2016.
- In December, several fields in Angola were subject to impairment charges as a result of falling oil prices. In total, $1.2 billion was recognized, a significant portion of which relates to the Angola LNG plant and is reflected in equity accounted earnings.

In Algeria BP, Sonatrach and Statoil are partners in the In Salah (BP 33.15%) and In Amenas (BP 45.89%) projects that supply gas to the domestic and European markets. BP s total assets in Algeria at 31 December 2015 were $1,625 million ($310 million current and $1,315 million non-current).

The Bourarhat agreement expired in September 2014 and talks with Sonatrach to negotiate new terms were not successful. Discussions with them to close out the project were initiated in the first half of 2015 and are ongoing.
In February 2016 the In Salah Southern Fields project start-up was announced. The project is the latest stage in the development of the In Salah Gas joint venture, which commenced production in 2004. The project s scope includes a new 500mmscfd gas dehydration central processing facility, brownfield modifications to existing processing facilities, 150km of carbon steel export pipelines, 160km of infield flowlines and the drilling and tie in of 26 new wells.

In Libya we partner with the Libyan Investment Authority (LIA) in an exploration and production-sharing agreement (EPSA) to explore acreage in the onshore Ghadames and offshore Sirt basins (BP 85%). BP served the National Oil Corporation with notices of force majeure in August 2014. 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. As a result of this uncertainty, balances associated with Libya were written off in 2015, incurring an exploration write-off of $432 million and other charges of $166 million.

In Egypt BP and its partners currently produce 10% of Egypt s liquids production and almost 30% of its gas production. BP s total assets at 31 December 2015 were $7,860 million, of which $1,739 million were current and $6,121 million were non-current. The current assets include trade receivables and Egyptian pound-denominated cash.

In March BP announced a gas discovery in the North Damietta offshore concession in the East Nile Delta at the Atoll-1 Deepwater exploration well (BP 100%). A Heads of Agreement was signed with the Egyptian government in November securing gas prices and key terms for the acceleration of Atoll development, with an estimated investment of around $900 million for the development of phase 1 of the project.
BP signed final agreements for the development of two West Nile Delta projects Taurus/Libra and Giza/Fayoum/Raven (BP 82.75%). Production from West Nile Delta is expected to start in 2017.
The West Nile Delta project concessions amendment, approved by the Egyptian cabinet in December 2014, was ratified in March 2015 and will be submitted to Parliament. The amendments agree a new development plan along with associated start-up dates.
In May BP signed a sales and purchase agreement with DEA Deutsche Erdoel AG under which BP increased its working interest in the West Nile Delta project concessions from 60% in North Alexandria Concession and 80% in West Mediterranean Deep Water Concession to 82.75% in both concessions. The transaction completed in December.
In August BP announced a further gas discovery at the Nooros prospect (BP 25%), located in the Abu Madi West concession in the Nile Delta in Egypt, operated by Eni.
In October BP was awarded three new exploration blocks in the Egyptian Natural Gas Holding Company 2015 bid round. The blocks are North El Tabya (BP 100%), North Ras El Esh (BP 50%) and North El Hammad (BP 37.5%). We and our partners have committed to investing over $200 million in the blocks across various phases.

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, Iraq and Russia.

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 13% 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 an output of more than 13 million tonnes.

In addition, BP participates in the Sanga-Sanga CBM PSA, where our working interest increased from 38% to 50% in January following withdrawal of Japan CBM Limited and Opicoil Energy at the end of 2014 and pending the Indonesian government s approval.

BP also exited the Tanjung IV PSA (BP 44%) in the Barito basin of Central Kalimantan in 2015, in accordance with the PSA and with government approval.

In China BP has a 30% equity stake in the 6.8 million tonnes per annum capacity Guangdong LNG regasification and pipeline project, 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 16.67%).

In Azerbaijan, BP operates two PSAs, Azeri-Chirag-Gunashli (ACG) (BP 35.8%) and Shah Deniz (BP 28.83%) and also holds other exploration leases.

* Defined on page 256.

- 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, and from the application of the new US sanctions, as they 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 is also excluded from the EU and US sanctions. For further information see International trade sanctions on page 242.
- In April we received final ratification by the government of Azerbaijan on the new PSA with the State Oil Company of the Republic of Azerbaijan, signed in December 2014, to jointly explore for and develop potential prospects in the shallow water area around the Absheron peninsula.
- The Shah Deniz Stage 2 project continues to move ahead with a number of milestones achieved ahead of schedule. The Shah Deniz Stage 2 project is now more than 50% complete in terms of engineering, procurement and construction, and remains on target for first gas in 2018.

BP holds a 30.1% interest in and operates 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 2015 of 716.7mboe/d.

BP is technical operator of, and currently holds a 28.83% interest in, the 693 kilometre South Caucasus Pipeline (SCP). The pipeline takes gas from Azerbaijan through Georgia to the Turkish border and has a capacity of 134mboe/d with average throughput in 2015 of 113.2mboe/d. BP (as operator of Azerbaijan International Operating Company) also operates the Western Export Route Pipeline that transports ACG oil to Supsa on the Black Sea coast of Georgia, with average throughput of 86mboe/d in 2015.

In April BP became a shareholder in the Trans Anatolian Natural Gas Pipeline (TANAP), and now holds a 12% equity share in the project. TANAP is a central part of the Southern Corridor pipeline system that will transport gas from the Shah Deniz field in Azerbaijan to markets in Turkey, Greece, Bulgaria and Italy.

In Oman, BP is continuing with development activity on the BP-operated Khazzan field in block 61 (BP 60%).

- By the end of 2015 10 rigs were operational, drilling the development wells at Khazzan. The project is more than 40% complete and work continues on the central processing facility and the associated infrastructure. Gas production is expected to start in late 2017.
- In February 2016 BP announced it had signed a heads of agreement with the government of the Sultanate of Oman to amend the block 61 EPSA, extending the licence area of the block and enabling further development of the Khazzan field.

In Abu Dhabi, we have an equity interest of 14.67% in an offshore concession. We also have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company that supplied 5.7 million tonnes of LNG (295.7bcfe regasified) in 2015.

In India, we have a 30% interest in four oil and gas PSAs operated by Reliance Industries Limited (RIL), and partner with RIL in a 50:50 joint operation for the gas sourcing and marketing in India.

- In 2015 a number of activities to sustain production and extend the life of the producing fields in KG D6 block were completed. These included well side-tracks, the installation of additional onshore compression, reactivation of

shut-in wells and production optimization.
We also undertook successful tests of three earlier discoveries; two in the KG D6 block and one in the NEC 25 block to progress towards Declaration of Commerciality.
We continue to expect further clarity on the gas price policy 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 in Southern Iraq. Rumaila is one of the world s largest oil fields, comprising five producing reservoirs. BP s total assets in Iraq at 31 December 2015 were $1,707 million ($1,281 million current and $426 million non-current). BP has undertaken studies with the government of Iraq and North Oil Company in support of the stabilization and redevelopment of two producing reservoirs in the Kirkuk field. Access to the Kirkuk field in 2015 was restricted due to the

security situation and the term of the agreement expired at the end of 2015. BP is entitled to recover all costs incurred to that date. Despite instability and sectarian violence in the north and west of the country, BP operations continued as planned in the south.

In Russia, we acquired a 20% participatory interest in a Rosneft subsidiary, Taas-Yuryakh Neftegazodobycha, in 2015, that will further develop the Srednebotuobinskoye oil and gas condensate field in East Siberia. Related to this, Rosneft and BP will jointly undertake exploration in an adjacent area of mutual interest.

Rosneft and BP have also agreed to jointly explore two additional areas of mutual interest in the prolific West Siberian and Yenisey-Khatanga basins where they will jointly appraise the Baikalovskoye discovery subject to receipt of all relevant consents. This is in addition to the exploration agreement announced in 2014 for an area of mutual interest in the Volga-Urals region of Russia where Rosneft and BP have commenced joint study work to assess potential non-shale, unconventional tight-oil* exploration projects (see Rosneft on page 38).

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 the region, 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, Maenad, Urania and Eurytion 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 in early 2016.

BP holds a 70% interest in four deepwater offshore exploration blocks in the Ceduna Sub Basin in the Great Australian Bight off the coast of southern Australia. BP, as operator, expects drilling to commence in late 2016 in this frontier exploration basin. It is also one of five participants in

the Browse LNG venture (operated by Woodside) and holds a 17% interest.

The Browse joint operation partners agreed to enter FEED for an offshore floating LNG concept in June. The proposed development remains subject to regulatory, joint venture and internal BP approvals.

In October the Western Flank A project (BP 16.67%) in offshore Western Australia began production. The Western Flank A project is the first of a series of subsea tie-back projects that have been undertaken to extend the production plateau and supply additional gas to the NWS s five existing LNG trains and domestic gas plant. The project is operated by Woodside.

The Persephone project (BP 16.67%) is the second of the NWS series of subsea tie-back projects and is on schedule to deliver first gas in the second half of 2017.

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, the Tangguh expansion project, remain on track, with first production expected in 2020.

The Tangguh expansion project is progressing, with completion of dual onshore FEED to two separate consortia on the third LNG train during 2015. Marketing on the third train capacity continues, with 65% of the volumes already contracted.

BP has 100% interests in two deepwater PSAs, West Aru I and II, and 32% interests 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 2015.

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	Australia	Kwinana	100	146
New Zealand	New Zealand	Whangarei[c]	21.2	26
Southern Africa	South Africa	Durban[c]	50	90
				262
Total BP share of capacity at 31 December 2015				1,853

[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.

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Petrochemicals production capacity[a]

The following table summarizes BP group s share of petrochemicals production capacities as at 31 December 2015.

			BP share of capacity thousand tonnes per annum[b]				
Geographical area	Site	Group interest (%)[c]	PTA	PX	Acetic acid	Olefins and derivatives	Product Others
US							
	Cooper River	100.0	1,300				
	Decatur[d]	100.0	1,000	700			
	Texas City	100.0		900	600[e]		100
			2,300	1,600	600		100
Europe							
UK	Hull[d]	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				3,500	
	Chongqing	51.0			200		100
	Nanjing	50.0			300		
	Zhuhai[h]	85.0	2,400				
Indonesia	Merak	100.0	500				
South Korea	Ulsan	34-51.0			300[g]		100[g]
Malaysia	Kertih	70.0			400		
Taiwan	Mai Liao	50.0			200		
	Taichung	61.4	500				
			3,400		1,400	3,500	900
			7,000	2,300	2,500	5,300	1,300
Total BP share of capacity at 31 December 2015							18,400

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

[b] Capacities are shown to the nearest hundred thousand tonnes per annum.

[c] Includes BP share of equity-accounted entities, as indicated.

[d] These sites have capacity under 100,000 tonnes per annum for a speciality product (e.g. naphthalene dicarboxylate and ethylidene diacetate). In January 2016 we announced the sale of the Decatur, US petrochemicals complex.

[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 2015 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 a weighted average 18% of our group proved undeveloped reserves (including the impact of disposals and price acceleration effects in PSAs) to proved developed reserves. This equates to a turnover time of about five and a half years. We expect the turnover time to remain near this level and anticipate the volume of proved undeveloped reserves held for more than five years to remain about the same.

In 2015 we progressed 959mmboe of proved undeveloped reserves (626mmboe for our subsidiaries alone) to proved developed reserves through ongoing investment in our subsidiaries and equity-accounted entities upstream development activities. Total development expenditure, excluding midstream activities, was $16,731 million in 2015 ($13,458 million for subsidiaries and $3,273 million for equity-accounted entities). The major areas with progressed volumes in 2015 were Angola, Azerbaijan, Russia, UK and US. Revisions of previous estimates for proved undeveloped reserves are due to changes relating to field performance, well results or changes in commercial conditions including price impacts. 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 2015	7,788
Revisions of previous estimates	300
Improved recovery	111
Discoveries and extensions	339
Purchases	126
Sales	(17)
Total in year proved undeveloped reserves changes	8,646
Progressed to proved developed reserves	(959)
Proved undeveloped reserves at 31 December 2015	7,687

Subsidiaries only	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2015	4,507
Revisions of previous estimates	61
Improved recovery	106
Discoveries and extensions	79
Purchases	101
Sales	(17)
Total in year proved undeveloped reserves changes	4,837
Progressed to proved developed reserves	(626)
Proved undeveloped reserves at 31 December 2015	4,211

[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.

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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 immediate review and all proved reserves require annual central authorization and have scheduled periodic reviews. The frequency of periodic review ensures that 100% of the BP proved reserves base undergoes central review every three 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 more than 10 years 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 2015, of certain properties owned by Rosneft as part of our equity-accounted proved reserves. The properties evaluated by D&M account for 100% of Rosneft s net proved reserves as of 31 December 2015. 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 2015 were held through joint operations* (84% in 2014), and 34% of the proved reserves were held through such joint operations where we were not the operator (33% in 2014).

Estimated net proved reserves of crude oil at 31 December 2015[a b c]

			million barrels
	Developed	Undeveloped	Total
UK	141	298	440
Rest of Europe	86	19	106
US	890	577	1,467
Rest of North America	46	205	252
South America	8	18	26
Africa	340	89	429
Rest of Asia	598	192	790
Australasia	35	16	51
Subsidiaries*	2,146	1,414	3,560
Equity-accounted entities	3,225	2,292	5,517
Total	5,371	3,707	9,078

Estimated net proved reserves of natural gas liquids at 31 December 2015[a b]

			million barrels
	Developed	Undeveloped	Total

UK	5	4	10
Rest of Europe	11	1	12
US	269	70	339
Rest of North America			
South America	7	28	35
Africa	5	10	15
Rest of Asia			
Australasia	9	2	12
Subsidiaries	308	115	422
Equity-accounted entities	45	15	60
Total	352	130	482

Estimated net proved reserves of liquids*

			million barrels
	Developed	Undeveloped	Total
Subsidiaries	2,453	1,529	3,982[d e]
Equity-accounted entities	3,270	2,307	5,577[f]
Total	5,723	3,836	9,560

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Estimated net proved reserves of natural gas at 31 December 2015[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	348	343	691
Rest of Europe	274	14	288
US	6,257	2,105	8,363
Rest of North America			
South America	2,071	5,989	8,060
Africa	847	2,305	3,152
Rest of Asia	1,803	3,455	5,257
Australasia	3,408	1,343	4,751
Subsidiaries	15,009	15,553	30,563[g]
Equity-accounted entities	6,856	6,778	13,634[h]
Total	21,865	22,331	44,197

Estimated net proved reserves on an oil equivalent basis

			million barrels of oil equivalent
	Developed	Undeveloped	Total
Subsidiaries	5,041	4,211	9,252
Equity-accounted entities	4,452	3,476	7,928
Total	9,493	7,687	17,180

[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 2015 marker prices used were Brent* $54.17/bbl (2014 $101.27/bbl and 2013 $108.02/bbl) and Henry Hub* $2.59/mmBtu (2014 $4.31/mmBtu and 2013 $3.66/mmBtu).

[c] Includes condensate and bitumen which are not material.

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 23 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 19 million barrels of liquids in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[f] Includes 70 million barrels of crude oil in respect of the 1.27% non-controlling interest in Rosneft held assets in Russia including 28 million barrels held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

[g] Includes 2,359 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[h] Includes 129 billion cubic feet of natural gas in respect of the 0.23% non-controlling interest in Rosneft held assets in Russia including 5 billion cubic feet held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

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 2015, on an oil equivalent basis including equity-accounted entities, decreased by 2% (decrease of 5% for subsidiaries and increase of 1% for equity-accounted entities) compared with 31 December 2014. Natural gas represented about 44% (57% for subsidiaries and 30% for equity-accounted entities) of these reserves. The change includes a net increase from acquisitions and disposals of 130mmboe (103mmboe within our subsidiaries and 28mmboe within our equity-accounted entities). Acquisition activity in our subsidiaries occurred in Egypt, Trinidad, the US and the UK, and divestment activity in our subsidiaries in Egypt, Trinidad, the US and the UK. In our equity-accounted entities the most significant item was a purchase in Russia.

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 2015, the proved reserves replacement ratio excluding acquisitions and disposals was 61% (63% in 2014 and 129% in 2013) for subsidiaries and equity-accounted entities, 28% for subsidiaries alone and 115% for equity-accounted entities alone. The ratio reflects lower reserves bookings as a result of a low number of final investment decisions adding new projects and reduced activity in Alaska and the US Lower 48. Lower prices impacted the reserves in a number of regions, but these were largely offset by increases in reserves in our PSAs. In some cases, cost recovery in PSAs may be limited by production or revenue caps.

In 2015 net additions to the group s proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 751mmboe (212mmboe for subsidiaries and 539mmboe 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 2015 principally resulted from the application of conventional technologies and increases in PSA entitlement as a result of lower prices. The principal proved reserves additions in our subsidiaries were in Angola, Azerbaijan, Canada, Egypt and Iraq. We had material reductions in our proved reserves in the US principally due to activity reduction and lower price. 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 2015 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.

Our Abu Dhabi offshore and Virginia Indonesia Company LLC (Western Indonesia) conventional concessions are 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 176.

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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
	2015	2014	2013	**2015**	2014	2013
Subsidiaries						
UK[c d]	**72**	46	58	**7**	2	3
Norway	**38**	41	31	**5**	5	4
Total Rest of Europe	**38**	41	31	**5**	5	4
Total Europe	**110**	87	89	**11**	7	7
Alaska[c]	**107**	127	137			
Lower 48 onshore[c]	**14**	14	12	**37**	45	45
Gulf of Mexico deepwater[c]	**203**	206	156	**19**	18	13
Total US	**323**	347	305	**56**	63	58
Canada	**3**					
Total Rest of North America	**3**					
Total North America	**327**	347	305	**56**	63	58
Trinidad & Tobago[c]	**12**	13	10	**11**	12	12
Brazil[c]			7			
Total South America	**12**	13	17	**11**	12	12
Angola	**221**	181	180			
Egypt[c]	**42**	37	33			
Algeria	**6**	5	3	**7**	5	3
Total Africa	**270**	222	217	**7**	5	3
Azerbaijan[c]	**111**	98	96			
Western Indonesia	**2**	2	1			
Iraq	**123**	55	39			
Other	**1**	2	4			1
Total Rest of Asia	**237**	156	141	**1**		1
Total Asia	**237**	156	141	**1**		1
Australia	**15**	17	19	**3**	3	4
Other	**2**	2	2			
Total Australasia	**17**	19	21	**3**	3	4
Total subsidiaries	**971**	844	789	**88**	91	86
Equity-accounted entities (BP share)						
TNK-BP (Russia, Venezuela, Vietnam)[c e]			183			4
Rosneft (Russia, Canada,Venezuela, Vietnam)[c f]	**809**	816	643	**4**	5	7
Abu Dhabi[g]	**96**	97	231			
Argentina	**65**	62	60	**3**	3	3

Bolivia	**4**	3	2			
Egypt				**3**	4	5
Other[c]	**1**	1	1			
Total equity-accounted entities	**974**	979	1,120	**10**	12	19
Total subsidiaries and equity-accounted entities[h]	**1,946**	1,823	1,909	**99**	104	105

[a] Includes condensate and bitumen which are not material.

[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 2015, BP acquired an interest in Taas-Yuryakh Neftegazodobycha. It also increased its interest in the North Alexandria and West Mediterranean Deep Water Concessions of the West Nile Delta project in Egypt. It increased its interest in certain UK North Sea, Trinidad, and US onshore assets. It also decreased its interest in certain other assets in the same Regions. 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.

[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] Estimated production for 2013 represents BP s share of TNK-BP s estimated production from 1 January to 20 March, averaged over the full year.

[f] 2015 is based on preliminary operational results of Rosneft for the three months ended 31 December 2015. Actual results may differ from these amounts. 2013 reflects production for the period 21 March to 31 December, averaged over the full year.

[g] BP holds interests, through associates, in offshore concessions in Abu Dhabi which expire in 2018. We also held onshore concessions which expired in 2014.

[h] Includes 4 net mboe/d of NGLs from processing plants in which BP has an interest (2014 7mboe/d and 2013 5.5mboe/d).

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]		
	2015	2014	2013
Subsidiaries			
UK[b]	**155**	71	157
Norway	**111**	102	80
Total Rest of Europe	**111**	102	80
Total Europe	**266**	173	237
Lower 48 onshore[b]	**1,353**	1,350	1,404
Gulf of Mexico deepwater[b]	**168**	159	114
Alaska	**7**	11	21
Total US	**1,528**	1,519	1,539
Canada	**10**	10	11
Total Rest of North America	**10**	10	11
Total North America	**1,538**	1,529	1,551
Trinidad & Tobago[b]	**1,922**	2,147	2,221
Total South America	**1,922**	2,147	2,221
Egypt[b]	**402**	406	444
Algeria	**187**	107	117
Total Africa	**589**	513	561
Azerbaijan[b]	**219**	230	203
Western Indonesia	**48**	47	51
India	**113**	131	156
Other[b]			81
Total Rest of Asia	**380**	408	490
Total Asia	**380**	408	490
Australia	**447**	450	431
Eastern Indonesia	**354**	364	353
Total Australasia	**801**	814	784
Total subsidiaries[c]	**5,495**	5,585	5,845
Equity-accounted entities (BP share)			
TNK-BP (Russia, Venezuela, Vietnam)[b d]			184
Rosneft (Russia, Canada, Venezuela, Vietnam)[b e]	**1,195**	1,084	617
Argentina	**341**	323	329
Bolivia	**93**	80	55
Other[b]	**21**	28	30
Total equity-accounted entities[c]	**1,651**	1,515	1,216
Total subsidiaries and equity-accounted entities	**7,146**	7,100	7,060

[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 2015, BP acquired an interest in Taas-Yuryakh Neftegazodobycha. It also increased its interest in the North Alexandria and West Mediterranean Deep Water Concessions of the West Nile Delta project in Egypt. It increased its interest in certain UK North Sea, Trinidad, and US onshore assets. It also decreased its interest in certain other assets in the same Regions. 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.

[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] 2015 is based on preliminary operational results of Rosneft for the three months ended 31 December 2015. 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										
2015										
Crude oil[c]	**52.42**	**50.68**	**49.84**	**26.71**	**53.19**	**49.09**		**41.41**	**50.64**	**47.78**
Natural gas liquids	**30.66**	**28.20**	**14.80**		**27.66**	**31.94**			**36.69**	**20.75**
Gas	**7.83**	**6.49**	**2.10**		**2.67**	**4.40**		**5.35**	**7.35**	**3.80**
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
Equity-accounted entities[d]										
2015										
Crude oil[c]					**54.24**		**44.78**	**16.87**		**41.49**
Natural gas liquids					**13.17**		**n/a**			**13.17**
Gas					**4.35**		**1.48**	**7.56**		**2.35**
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

[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.

[b] The operational and financial information of the Rosneft segment for 2015 is based on preliminary operational and financial results of Rosneft for the three months ended 31 December 2015. Actual results may differ from these amounts. Crude oil includes natural gas liquids.

[c] Includes condensate. 2015 for subsidiaries also includes bitumen.

[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										
2015	**22.95**	**13.80**	**11.84**	**43.56**	**5.44**	**11.02**		**9.81**	**2.88**	**10.26**
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
Equity-accounted entities										
2015					**12.10**		**2.60**	**4.59**		**3.93**
2014					11.28		3.82	4.34		4.75
2013					12.16		4.36	4.19		5.28

[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] The operational and financial information of the Rosneft segment for 2015 is based on preliminary operational and financial results of Rosneft for the three months ended 31 December 2015. Actual results may differ from these amounts.

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Environmental expenditure

			$ million
	2015	2014	2013
Environmental expenditure relating to the Gulf of Mexico oil spill	**5,452**	190	(66)[a]
Operating expenditure	**521**	624	657
Capital expenditure	**733**	590	1,091
Clean-ups	**34**	33	42
Additions to environmental remediation provision	**305**	371	472
Additions to decommissioning provision	**972**	2,216	2,092

[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, treatment or elimination of air and water emissions and solid waste is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction that includes, for example, normal operations and 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 $521 million in 2015 (2014 $624 million) decreased primarily due to Downstream reduced level of turnaround activity in 2015.

Environmental capital expenditure in 2015 was higher than in 2014, primarily driven by the installation of a dissolved nitrogen floatation unit at Whiting refinery s wastewater treatment plant that is designed to improve the quality of cleaned water before it leaves the refinery. The increase also reflects the investment at our Cooper River, US and Geel, Belgium petrochemicals site to upgrade it to our latest generation PTA technology that is expected to significantly increase manufacturing efficiency resulting in lower greenhouse gas emissions and improved energy efficiency.

Clean-up costs increased to $34 million in 2015 compared with $33 million in 2014, primarily due to higher remediation management costs.

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.

In 2015 the additions to the environmental provision were lower as 2014 included more new sites and increased provisions from existing sites resulting from recent acquisitions. The charge for environmental remediation provisions in 2015 included $6 million in respect of provisions for new sites (2014 $13 million and 2013 $13 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 2015 additions to the decommissioning provision were less than in 2014, and occurred as a result of detailed reviews of expected future costs. The majority of these additions related to our sites in the North Sea, the Gulf of Mexico and Angola. The additions in 2013 and 2014 were driven by detailed reviews of expected future costs, increases to the asset base and for 2013, changes in estimation processes.

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 22.

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 more than 70 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 and by 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 (including control of vehicle emissions), 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 or properties. 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 22 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 233.

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. The revised lower ambient air quality standard for ozone, finalized by the Environmental Protection Agency (EPA) in October 2015, as well as proposed new restrictions on methane and volatile organic emissions and on gas flaring, will affect our US operations in the future. 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 carbon fuel standards as well as Low Emission Vehicle (LEV) and Zero Emission Vehicle (ZEV) standards imposed on vehicle manufacturers. These regulations will have an impact on fuel demand and product mix in California and those states adopting LEV and ZEV 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 notification of releases of hazardous substances to national, state and local government agencies, as applicable. In addition, the Emergency Planning and Community Right-to-Know Act requires notification of releases of designated quantities of certain listed hazardous substances to state and local government agencies, as applicable.

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, requiring continuous evaluation and improvement of operational practices to enhance safety and reduce workplace emissions at gas processing and refining facilities.

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 required BP to reassess the hazards of all of its chemicals and products against new GHS criteria as adopted or modified by OSHA and warning labels and safety data sheets were updated 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.

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The Maritime Transportation Security Act, the DOT Hazardous Materials (HAZMAT) and the Chemical Facility Anti-Terrorism Standard regulations impose security compliance regulations on around 15 BP facilities.

OPA 90 is implemented through regulations issued by the 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.

The Outer Continental Shelf Land Act and other statutes give the Department of Interior (DOI) and the Bureau of Land Management (BLM) authority to regulate operations and air emissions on offshore and onshore operations on federal lands subject to DOI authority. New stricter regulations on operational practices, equipment and testing have been imposed on our operations in the Gulf of Mexico and elsewhere following the Deepwater Horizon oil spill.

European Union

In October 2014, the European Council agreed on new climate and energy targets for the period up to 2030. Specifically, Member States have agreed to a 40% reduction in GHG emissions below 1990 levels and to a 27% share of renewable energy in final energy consumption. Specific EU legislation and agreements required to achieve these goals are not yet in place.

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 (see Greenhouse gas regulation below), the EU Fuel Quality Directive and the Renewable Energy Directive.

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 Renewable Energy Directive requires Member States to have 10% (by energy content) of final transportation fuel to be derived from renewable energy, such as biofuels and renewable electricity. This target must be met by the end of 2020.

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 has been implemented in the UK by the Energy Savings Opportunity Scheme Regulations 2014, which affects our offshore and onshore assets. The ISO50001 standard is being implemented by organizations in some EU states to meet some elements of the Energy Efficiency Directive.

The Industrial Emissions Directive (IED) 2010 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 BAT Conclusions for the refining sector and for combustion.

The National Emission Ceiling Directive 2001 is currently being revised and subsequent source-control measures by Member States may be required to meet national emissions targets. These may result in further emission reduction requirements.

The EU regulation on ozone depleting substances (ODS) 2009 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 greenhouse gases with high global warming potential (the F-gas Regulations) came into force on 1 January 2015. The F-gas Regulations require a phase-out of certain hydrofluorocarbons, based on global warming potential.

European regulations also establish passenger car performance standards for CO_2 tailpipe emissions (European Regulation (EC) No

443/2009). From 2020 onwards, the European passenger fleet emissions target is 95 grams of CO_2 per kilometre. This target will be achieved by manufacturing fuel efficient vehicles and vehicles using alternative, low carbon fuels such as hydrogen and electricity. In addition, vehicle emission test cycles and vehicle type approval procedures are being updated to improve accuracy of emission and efficiency measurements. Consequently, product mix and overall levels of demand will be impacted.

European vehicle CO_2 emission regulations also impact the fuel efficiency of vans. By 2020, the EU fleet of newly registered vans must meet a target of 147 grams of CO_2 per kilometre, which is 19% below the 2012 fleet average.

The EU Registration, Evaluation Authorization and Restriction 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 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 or checking that BP imports are covered by the registrations of non-EU suppliers only representatives. BP continues to maintain compliance by submitting registrations to cover new manufactured and imported substances, and to update previously submitted registrations as required. Some substances registered previously, including substances supplied to us by third parties for our use, are now subject to evaluation and review for potential authorization or restriction procedures, and possible banning, by the European Chemicals Agency and EU Member State authorities.

In addition, the EU implemented the UN s Globally Harmonized System of Classification and Labelling of Chemicals (GHS) 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. From 1 June 2015, the CLP Regulation applies in full to mixtures (e.g. lubricants) that are placed on the market. 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 updated to include both REACH and CLP information.

The EU Offshore Safety Directive was adopted in 2013. 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. The Directive has been implemented in the UK primarily through the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015.

The implementation of the Water Framework Directive 2000 and the Environmental Quality Standards Directive 2008 may mean that BP has to take further steps to manage freshwater withdrawals and discharges from its EU operations.

Regulations governing the discharge of treated water have also been developed in countries outside of the US and EU. This includes regulations in Trinidad and Angola. In Trinidad, BP has been working with the regulators to apply water discharge rules arising from the Certificate of Environmental Clearance (CEC) Regulations 2001, and associated Water Pollution Rules 2007. In Angola, BP has been upgrading produced water treatment systems to meet revised Oil in Water limits for produced water discharge under Executive Decree ED 97-14 (superseded ED 12/05 on 1 January 2016).

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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 at year end, as the required minimum number of contracting states had not been achieved, the HNS Convention has not yet entered into force.
- Changes to the permitted level of sulphur in marine fuels under EU mandated reductions for European waters and International Maritime Organization (IMO) regulations are being phased in until 2020, when the low sulphur rules for shipping in global waters are scheduled to take effect. Depending on the outcome of ongoing IMO deliberations, the regulations impacting operations in global waters may be delayed until 2025. Regulations requiring the reduction of sulphur oxides emissions will require ships to either burn low sulphur marine fuels or continue using higher sulphur fuel along with approved on-board sulphur abatement technology. Compliance with the IMO regulations may 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

In 2011, parties to the UN Framework Convention on Climate Change (Framework Convention) at the Conference of the Parties (COP17) in Durban 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 in Doha (COP18) establishing a second commitment period to run until the end of 2020. However, it did not include the US, Canada, Japan and Russia and thus covers only about 15% of global emissions.

The 2014 conference in Lima (COP20) 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, that would 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 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.

In December 2015, 195 nations at the United Nations climate change conference in Paris (COP21) adopted the Paris Agreement, for implementation post-2020. This will come into force when it has been ratified by at least 55 of the parties to the Framework Convention, representing at least 55% of global GHG emissions. For the first time this binds all participants to its provisions and encourages voluntary contributions by developing countries. The Paris Agreement aims to hold global average temperature rise to well below 2ºC above pre-industrial levels and to pursue efforts to limit temperature rise to 1.5ºC above pre-industrial levels. There is no quantitative long-term emissions goal but countries aim to reach global peaking of GHG emissions as soon as possible and to undertake rapid reductions thereafter to achieve a balance between human caused emissions and natural absorption in the second half of this century. The Paris Agreement places binding commitments on all parties, from 2020, to make Nationally Determined Contributions (NDCs) and pursue domestic measures aimed at achieving the objectives of their NDCs. Developed country NDCs should include absolute emission reduction targets, and developing countries are encouraged to move over time towards them. The Paris Agreement places binding commitments on countries, starting by 2023, to report on their emissions and progress made on their NDCs; undergo international review of collective progress; and submit new, more ambitious NDCs every five years. The Paris Agreement extends the existing goal for climate finance to a minimum of $100 billion after 2025.

More stringent national and regional 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 was 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 included 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 (including the petrochemicals sector) and gases; no free allocation for electricity generation (including that which is self-generated off-shore) or production, but benchmarked free allocation for energy-intensive and trade-exposed industrial sectors. EU ETS revisions also included the adoption of a Market Stability Reserve to reduce the supply of auctioned allowances. This will take effect in 2019 and could potentially lead to higher carbon costs. 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 agreed to the 2030 Climate and Energy Policy framework 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.

Canada s highest emitting province, Alberta, has regulations targeting large final emitters (sites with over 100,000 tonnes of carbon dioxide equivalent per annum) with intensity targets of 2% improvement per year up to 20%. Compliance is possible via direct reductions, the purchase of offsets or the payment of C$20/tonne to a technology fund which will escalate to $30/tonne in 2017. A new policy direction has just been announced for post-2018 where performance relative to a best in sector benchmark (to be determined) will now determine the volume of emissions subject to a cost ($30/tonne escalating in real terms) or use of other compliance mechanisms such as offsets.

In the US, the EPA continues to pursue regulatory measures to address GHGs under the CAA.

EPA regulations impose light, medium and heavy duty vehicle emissions standards for GHGs and permitting requirements for certain large GHG stationary emission sources. The EPA and the National Highway Traffic Safety Administration are considering a proposed rulemaking to extend and tighten GHG emission and fuel efficiency standards until 2027. This will have an impact on BP s product mix and overall demand.

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 Clean Energy Plan Regulation that establishes GHG reduction requirements, at a state or regional level, for existing power plants. The new and modified power plant rule was finalized in August 2015 while the existing power plant rule was finalized in October 2015. Legal challenges to both rules have been filed by a number of US States; utility, coal, and mining companies; and the US Chamber of Commerce. 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.

In January 2015, the US government announced plans to reduce methane emissions from the oil and gas sector by 40-45% from 2012 levels by 2025. In September 2015, the EPA proposed rules aimed at limiting methane emissions from the oil and natural gas sector in the US with plans to finalize these rules in early 2016. In January 2016, the BLM released proposed rules aimed at limiting methane emissions on federal lands from new, modified and existing sources in the oil and gas sector. If implemented as proposed, these EPA and BLM rules will require further actions by our US upstream businesses to manage methane emissions.

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 November 2014 US-China joint announcement on climate change addressing post-2020 actions, which was reaffirmed by the countries respective presidents in 2015, 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 CO_2 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 pilot programmes in five cities and two provinces. A number of BP joint venture* companies in China are participating in these schemes. A nationwide carbon emissions trading market is expected to be launched in 2017 following the above seven pilot programmes.

China has also adopted more stringent vehicle tailpipe emission standards and vehicle efficiency standards to address air pollution and GHG emissions. These standards will have an impact on transportation fuel product mix and overall demand.

South Africa has delayed implementation of a carbon tax on carbon intensive emitters until 2017.

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 46.

Legal proceedings

Proceedings relating to the Deepwater Horizon oil spill

Introduction

BP Exploration & Production Inc. (BPXP) was lease operator of Mississippi Canyon, Block 252 in the Gulf of Mexico (Macondo), where the semi-submersible rig Deepwater Horizon was deployed at the time of the 20 April 2010 explosions and fire and resulting oil spill (the Incident). The other working interest owners at the time of the Incident were Anadarko Petroleum Company (Anadarko) and MOEX Offshore 2007 LLC, claims against whom were settled by BP in 2011. The Deepwater Horizon, which was owned and operated by certain affiliates of Transocean Ltd. (Transocean), sank on 22 April 2010. Lawsuits and claims arising from the Incident have generally been brought in US federal and state courts. The lawsuits have asserted, 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. The plaintiffs include individuals, corporations, insurers and governmental entities and many of the lawsuits purport to be class actions.

Many of the lawsuits in federal court were 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 Employee Retirement Income Security Act (ERISA) cases (MDL 2185) and another in federal district court in New Orleans for the remaining cases (MDL 2179). A Plaintiffs Steering Committee (PSC) was established to act on behalf of individual and business plaintiffs in MDL 2179. These proceedings, and other material ongoing lawsuits and claims arising from the Incident are discussed below.

Federal and state claims

MDL 2179 Department of Justice (DoJ) Action and Trial of Liability, Limitation, Exoneration and Fault Allocation

The US filed a civil complaint in MDL 2179 against BPXP and others on 15 December 2010 (the DoJ Action). The complaint sought an order finding liability under OPA 90 for natural resources damages and civil penalties under the Clean Water Act (CWA). 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, a Trial of Liability, Limitation, Exoneration and Fault Allocation (the Trial) in MDL 2179 commenced on 25 February 2013.

The district court issued its ruling on the first phase of the Trial in September 2014. BPXP, BP America Production Company (BPAPC) and various other parties were each found 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 CWA, the district court found that the discharge of oil was the result of BPXP s gross negligence and wilful misconduct and that BPXP was therefore subject to enhanced civil penalties.

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 and were therefore subject to a CWA penalty. In addition, the district court found that BP was not grossly negligent in its source control efforts. For further details of the Trial, see Legal proceedings in *BP Annual Report and Form 20-F 2014.*

BP appealed both rulings.

The penalty phase of the Trial involved consideration of the amount of CWA civil penalties owed to the United States, and concluded in February 2015. Briefing concluded on the post-trial briefing schedule for the penalty phase on 24 April 2015.

State and local authority claims consolidated into MDL 2179

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. In addition, the Louisiana Department of Environmental Quality issued an administrative order seeking environmental civil penalties and other relief under state law.

On 10 December 2010, the Mississippi Department of Environmental Quality issued a Complaint and Notice of Violation alleging violations of several state environmental statutes.

In April 2013, the states of Alabama, Florida and Mississippi each filed actions against BP related to the Incident, including 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.

On 17 May 2013, the State of Texas filed suit against BP and others in federal court in Texas. Its complaint asserted 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; and claims for natural resource damages, cost recovery, civil penalties and economic damages under state environmental statutes.

Each of these actions filed by the Gulf Coast states was consolidated with MDL 2179.

On 28 August 2015, the district court in MDL 2179 issued an order dismissing the local government entity master complaint in view of the fact that the vast majority of local government entity plaintiffs who had preserved their claims had released their claims as part of the local government entity settlement with BPXP (as described below under Consent Decree and Settlement Agreement). With respect to claims by local government entities that have not released their claims, the court held that they are time-barred except to the extent that those local government entities previously made timely presentment of their claims under OPA 90 and previously filed either a complaint or a valid short-form joinder in the MDL 2179 master complaint for local government entities.

Consent Decree and Settlement Agreement

On 2 July 2015, BP announced that BPXP had executed agreements in principle with the United States federal government and five Gulf Coast states to settle all federal and state claims arising from the Incident. In addition to settling claims with the states of Alabama, Florida, Louisiana, Mississippi and Texas, BPXP also settled the claims made by more than 400 local government entities.

On 5 October 2015, the United States lodged with the district court in MDL 2179 a proposed Consent Decree between the United States, the Gulf states and BP to fully and finally resolve any and all natural resource damages claims of the United States, the Gulf states and their respective natural resource trustees and all CWA penalty claims, and certain other claims of the United States and the Gulf states. Concurrently, BP entered into a definitive Settlement Agreement with the five Gulf states (Settlement Agreement) with respect to state claims for economic, property and other losses. The United States is expected to file a motion with the court to enter the Consent Decree as a final settlement around the end of March, which the court will then consider. The time period for public comments on the Consent Decree ended on 4 December 2015.

The proposed Consent Decree and the Settlement Agreement are conditional upon each other and neither will become effective unless there is final court approval of the Consent Decree. A further condition of the agreements in principle was that local government entities execute releases to BP s satisfaction. BP advised the court that it was satisfied with and has accepted releases received from the vast majority of local entities. Accordingly, on 27 July 2015, the district court ordered BP to commence processing payments required under the releases and BP made such payments in accordance with the court s order.

The principal payments are as follows:

- BPXP is to pay the United States a civil penalty of $5.5 billion under the CWA payable over 15 years.
- BPXP will pay $7.1 billion to the United States and the five Gulf states over 15 years for natural resource damages (NRD). This is in addition to the $1 billion already committed for early restoration. BPXP will also set aside an additional amount (up to $700 million) consisting of $232 million and the NRD interest payment (see below) partly to cover any further natural resource damages that are unknown at the time of the agreement.
- A total of $4.9 billion will be paid over 18 years to settle economic and other claims made by the five Gulf Coast states.
- Up to $1 billion to resolve claims made by more than 400 local government entities.

BPXP has also agreed to pay $350 million to cover outstanding NRD assessment costs and $250 million to cover the full settlement of outstanding response costs, claims related to the False Claims Act and royalties owed for the Macondo well. These additional payments will be paid over nine years, beginning in 2015.

NRD and CWA payments are scheduled to start 12 months after the Consent Decree and the Settlement Agreement become effective. The 2016 payments in respect of the state claims are due within 90 days of the Settlement Agreement becoming effective. Total payments for NRD, CWA and state claims will be made at a rate of around $1.1 billion a year for the majority of the payment period.

Interest will accrue at a fixed rate on the unpaid balance of the CWA and NRD payments, compounded annually and payable in year 16. To address possible natural resource damages unknown at the time of the settlement, beginning 10 years after the Consent Decree and the Settlement Agreement become effective, the federal government and the five Gulf states may request accelerated payment of accrued but unpaid interest on the NRD payments.

Parent company guarantees for these payments will be provided by BP Corporation North America Inc. as the primary guarantor and BP p.l.c. as the secondary guarantor.

The federal government and the Gulf states may jointly elect to accelerate the payments under the Consent Decree in the event of a change of control or insolvency of BP p.l.c., and the Gulf states individually have similar acceleration rights under the Settlement Agreement.

The proposed Consent Decree and Settlement Agreement do not cover the remaining costs of the 2012 class action settlements with the PSC for economic and property damage and medical claims. They also do not cover claims by individuals and businesses that opted out of the 2012 PSC settlements and/or whose claims were excluded from them, including claims for recovery of losses allegedly resulting from the 2010 federal deepwater drilling moratoria and/or the related permitting processes. The proposed Consent Decree and Settlement Agreement also do not resolve private securities litigation pending in MDL 2185. Each of these outstanding proceedings and claims is discussed further below.

On 5 October 2015, on the joint motion of BP and the five Gulf states, the district court dismissed the five Gulf states claims (with the exception of claims for NRD and CWA penalties being addressed by the proposed Consent Decree) against BP. The dismissal is without prejudice pending the court s entry of the Consent Decree, which is required for the Settlement Agreement with the Gulf states to become effective, at which time the dismissal would be converted into a dismissal with prejudice.

OPA 90 Test Case Proceedings

A number of lawsuits have been brought, primarily from business claimants, under OPA 90 in relation to the 2010 federal deepwater drilling moratoria. Following the dismissal of one test case in January 2016, six test cases, consolidated with MDL 2179, will address certain OPA 90 liability questions focusing on, among other issues, whether plaintiffs alleged losses tied to the moratoria and whether federal permit delays are compensable. In December 2015, BP filed a motion to dismiss plaintiffs claims arising from the moratoria or permit process, and

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plaintiffs filed a motion asking the court to prevent BP from arguing that government action and/or inaction following the oil spill is a superseding cause with respect to some or all of the damages that plaintiffs claim. The motions are fully briefed, but the court has not yet issued a ruling.

Halliburton and Transocean settlements.

On 20 May 2015, BP and Transocean, and BP and Halliburton Energy Services Inc. (Halliburton), entered into confidential settlement agreements to resolve the final remaining disputes between these parties stemming from the Incident.

Under the agreement with Transocean, BPXP and BPAPC agreed to indemnify Transocean for compensatory damages (including natural resource damages), to pay Transocean $125 million in compensation for incurred legal fees, and discontinue attempts to recover as an additional insured under Transocean s liability policies. Transocean agreed to indemnify BPXP and BPAPC for the personal and bodily injury claims of Transocean employees, as well as for claims relating to any future cleanup or removal of diesel or other pollutants stored on the Deepwater Horizon. BPXP, BPAPC, and Transocean will mutually release all claims between the companies.

BPXP s agreement with Halliburton resolves the remaining claims between the two companies and includes indemnities and the dismissal of all claims against each other.

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. To date, BP and the trustees have reached agreement on a total of 65 early restoration projects that are expected to cost approximately $877 million. The remaining unpaid balance of the $1 billion will be paid within 30 days after court approval of the proposed Consent Decree.

Under the proposed Consent Decree, Trustees would continue to implement these early restoration projects as part of the final settlement of all US and state claims for natural resource damages.

PSC settlements

PSC settlements Economic and Property Damages Settlement Agreement

The Economic and Property Damages Settlement resolves certain economic and property damage claims, and includes a $2.3 billion BP commitment to help resolve economic loss claims related to the Gulf seafood industry (which we refer to as the Seafood Compensation Fund) and a $57-million fund to support advertising to promote 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 cover claims by individuals and businesses that opted out of the 2012 PSC settlements and/or whose claims were excluded from them, including claims for recovery of losses allegedly resulting from the 2010 federal deepwater drilling moratoria and/or the related permitting processes. The Economic and Property Damages Settlement also does not resolve private securities litigation pending in MDL 2185.

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 provided that, to the extent permitted by law, BP assigned 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. The claims facility operating under the framework established by the Economic and Property Damages Settlement commenced operation in June 2012. Following numerous court decisions on 31 March 2015, the court denied the PSC s motion seeking to alter or amend a revised policy, addressing the matching of revenue and expenses for business economic loss claims, which requires 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 23 April 2015, the PSC appealed this decision to the Fifth Circuit. On 18 December 2015, the PSC and BP entered into a joint stipulation to stay this appeal pending resolution of certain issues in the district court in New Orleans. On 8 January 2016, the Fifth Circuit granted the joint stipulation and stayed the appeal for 120 days.

The effective date of the Economic and Property Damages Settlement Agreement was 8 December 2014, and the final deadline for filing all claims other than those that fall into the Seafood Compensation Program was 8 June 2015.

On 8 May 2015, the Fifth Circuit upheld three awards to non-profit entities under the Economic and Property Damages Settlement, each of which was premised on an official policy that typically treated grant monies and contributions to non-profit entities as revenue for purposes of the settlement s calculations. BP argued that this policy was inconsistent with the language of the settlement agreement and would place the agreement in violation of United States law, but the Fifth Circuit upheld the policy and determined that the district court did not otherwise abuse its discretion in denying review of the three awards. The court also held that requests for discretionary review of settlement claims by BP or individual claimants under the Economic and Property Damages Settlement can be appealed by BP or individual claimants to the Fifth Circuit.

For more information about BP s current estimate of the total cost of the Economic and Property Damages Settlement, see Financial statements Note 2.

PSC settlements Medical Benefits Class Action Settlement

The Medical Benefits Class Action Settlement (Medical Settlement) resolves certain medical claims by response workers and Gulf Coast residents. Under the Medical Settlement, class members release and dismiss their claims against BP covered by that settlement, except that class members do not release certain claims for later-manifested physical conditions (LMPCs).

The Medical Settlement involves payments to qualifying class members based on a matrix for certain Specified Physical Conditions (SPCs), as well as a 21-year Periodic Medical Consultation Program (PMCP) for qualifying class members. The Medical Settlement also provides that class members claiming LMPCs 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 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 $93.7 million for projects sponsored by this programme.

The district court approved the Medical Settlement in a final order and judgment on 11 January 2013. The effective date was 12 February 2014 and the deadline for submitting claims was 12 February 2015. The total number of claims estimated by the Medical Claims Administrator is approximately 37,200. At year end, approximately 7,600 SPC claims, totalling approximately $17 million, have been approved for compensation. In addition, approximately 22,000 claimants have been determined eligible for the PMCP.

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).

*Defined on page 256.

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Securities class action

On 20 May 2014, the court 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. The parties appealed the district court s class certification decisions and on 8 September 2015, the Fifth Circuit affirmed both of the district court s decisions. On 26 October 2015, the Fifth Circuit denied the pre-explosion ADS purchasers motion for rehearing en banc. On 25 January 2016, the pre-explosion ADS purchasers filed in the Supreme Court a petition for a writ of certiorari seeking review of the Fifth Circuit s decision. The trial of the securities fraud claims of the class of post explosion ADS purchasers has been scheduled to commence on 5 July 2016.

Individual securities litigation

From April 2012 to September 2015, 37 cases were filed in state and federal courts by pension funds and investment funds and advisers 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 claims under English law and, for plaintiffs purchasing ADSs, federal securities law, and seek damages for alleged losses that those funds suffered because of their purchases of BP ordinary shares and/or ADSs. All the cases, with the exception of one case that has been stayed, have been transferred to MDL 2185. In August and September 2015, plaintiffs filed or sought leave to file amended complaints in those cases. On 4 January 2016, the district court dismissed two of those cases and some of the claims of a third case with leave to replead by 19 January 2016. Plaintiffs in the two dismissed cases filed amended complaints on 19 January 2016.

Canadian class action

On 15 November 2012, a plaintiff re-filed a statement of claim against BP in Ontario, Canada, 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. On 14 August 2014, the Ontario Court of Appeal held 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 26 March 2015, the Supreme Court of Canada dismissed the plaintiff s appeal of this decision. Plaintiff has not amended his complaint to assert claims on behalf of Canadian residents who purchased ADSs on the Toronto Stock Exchange, and thus there have been no further proceedings in the case. On 27 March 2015, the plaintiff filed a complaint in Texas federal court asserting claims under Canadian law against BP on behalf of a class of Canadian residents who allegedly suffered losses because of their purchase of BP ADSs on the New York Stock Exchange. That action was transferred to MDL 2185 and was dismissed by the district court on 25 September 2015. The time to appeal that dismissal has expired.

Dividend-related proceedings

On 11 May 2015, the Fifth Circuit affirmed a district court decision in June 2014 dismissing an action against BP p.l.c. for cancelling its dividend payments in June 2010 on the grounds that the courts of England were the more appropriate forum for the litigation. This followed earlier unsuccessful lawsuits against BP p.l.c. for the 2010 dividend payment cancellation.

ERISA

On 15 January 2015, following an earlier dismissal in the ERISA case related to BP share funds in several employee benefit savings plans, the district court allowed the plaintiffs to amend their complaint to allege some of their proposed claims against certain defendants. The district court certified that decision for appeal, and the Fifth Circuit accepted that appeal on 20 May 2015. Plaintiffs filed an amended complaint on 12 February 2015. On 30 October 2015, the district court granted defendants partial motion to dismiss, dismissing some of the claims in the amended complaint.

Other Deepwater Horizon oil spill related claims

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. 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, including state law claims, claims for punitive damages and claims for medical monitoring damages. In each case 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 complaints to those individual complaints.

On 4 September 2015, the district court in MDL 2179 issued an order directing the clerk to docket no further joinders by plaintiffs in the two master complaints for private plaintiff economic and property damages claims and for medical claims.

On 14 September 2015, the district court granted BP s motion for summary judgment and issued a judgment dismissing with prejudice the Center for Biological Diversity s claim against BP under the Emergency Planning and Community Right to Know Act. This followed an earlier unsuccessful appeal against the dismissal of the other action brought against BP by the Center for Biological Diversity. On 8 October 2015, the Center for Biological Diversity filed a motion asking the district court to reconsider its 14 September 2015 order. That motion was denied on 4 December 2015.

Non-US government lawsuits

On 1 May 2015, the Fifth Circuit affirmed the district court s dismissal with prejudice of the claims brought in September 2010 by three Mexican states bordering the Gulf of Mexico (Veracruz, Quintana Roo and Tamaulipas) against several BP entities. The 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 30 July 2015, the three Mexican states filed a petition for certiorari to the US Supreme Court, which was denied on 30 November 2015.

On 5 April 2011, the Mexican 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. This was followed by a suit against BP which 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.

On 18 October 2012, before a Mexican Federal District Court located in Mexico City, a class action complaint was filed against BPXP, BPAPC, and other BP subsidiaries. The plaintiffs, consisting of fishermen and other groups, are seeking, among other things, compensatory damages for the class members who allegedly suffered economic losses, as well as an order requiring BP to remediate environmental damage resulting from the Incident, to provide funding for the preservation of the environment and to conduct environmental impact studies in the Gulf of Mexico for the next 10 years. After initial dismissal of the action, it was reported in December 2015 that the action was reinstated after appeal, although BP has not been formally served with the action.

False Claims Act actions

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 Qui Tam (whistle-blower) provisions of the False Claims Act (FCA). 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. Under the terms of the proposed Consent Decree, the United States and Gulf states would covenant not to pursue claims against BP under the FCA.

Criminal settlement with the DoJ and settlement with the SEC

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 sentenced BP in connection with the criminal plea agreement. Pursuant to that sentence, BP is required to 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 is required to be paid to the National Fish & Wildlife Foundation (NFWF) over five years. In addition, $350 million is required to 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, January 2015 and January 2016 totalling $2.1 billion. BP was required to serve a term of five years probation and agree to certain equitable relief relating to BP s risk management processes in order to further enhance the safety of drilling operations in the Gulf of Mexico. BP also agreed to maintain a real-time drilling operations monitoring centre and to undertake several initiatives with academia and regulators to develop new technologies related to deepwater drilling safety. The resolution also provided for the appointment of two monitors, a process safety monitor, to review and provide recommendations concerning BPXP s process safety and risk management procedures for deepwater drilling in the Gulf of Mexico and an ethics monitor, to review and provide recommendations concerning BP s ethics and compliance programme. BP has also agreed to retain an independent third-party auditor to review and report to the probation officer, the DoJ and BP regarding BPXP s compliance with the key terms of the plea agreement. 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 agreed to a civil penalty of $525 million, the last instalment of which was paid in August 2014, and consented to the entry of an injunction prohibiting it from violating certain US securities laws and regulations.

US Environmental Protection Agency matters

On 13 March 2014, BP, BPXP, and all other temporarily suspended BP entities entered into an administrative agreement with the US Environmental Protection Agency (EPA) resolving all issues related to suspension or debarment arising from the Incident. Under the terms and conditions of the administrative agreement, which will apply until 13 March 2019, BP may enter into new contracts or leases with the US government but must comply with a set of safety and operations, ethics and compliance and corporate governance requirements.

US Department of Interior matters

On 12 October 2011, the US Department of the Interior Bureau of Safety and Environmental Enforcement issued to BP, Transocean, and Halliburton Notification of Incidents of Noncompliance (INCs). The notification issued to BP is for a number of alleged regulatory violations concerning Macondo well operations. On 7 December 2011, the Bureau of Safety and Environmental Enforcement issued to BP a second INC for five alleged violations related to drilling and abandonment operations at the Macondo well. BP filed an administrative appeal with respect to the first and second

INCs and filed a joint stay of proceedings with the Department of Interior with respect to both INCs. Pursuant to the proposed Consent Decree with the United States (see above), if entered by the court, BP would withdraw its appeals within 15 days of the effective date of the Consent Decree, and the INCs would then be fully and finally resolved.

Pending investigations and reports relating to the Deepwater Horizon oil spill CSB investigation

The US Chemical Safety and Hazard Investigation Board (CSB) has indicated that it plans to release the final two volumes of its four-volume report on its investigation into the Incident (concerning the role of the regulator in the oversight of the offshore industry and organizational and cultural factors) in March 2016.

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 in 2008. 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 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 proposed a civil penalty of $28 million and the surrender of $800,000 of alleged profits. The Administrative Law Judge ruled on 13 August 2015 that BP manipulated the market by selling next-day, fixed price natural gas at Houston Ship Channel in 2008 in order to suppress the Gas Daily index and benefit its financial position. BP filed an appeal to the initial decision with the FERC on 14 September 2015 and the Office of Enforcement filed an opposing brief on 5 October 2015.

Canadian Pipeline Nominations

The 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

In March 2007, the CSB issued a report on the March 2005 explosion and fire at the Texas City refinery incident. The report contained recommendations to the BP Texas City refinery and to the board of directors of BP. To date, the CSB has accepted that all but one of BP s responses to its recommendations have been satisfactorily addressed. BP and the CSB are continuing to discuss the remaining open recommendation with the objective of the CSB agreeing to accept this as satisfactorily addressed as well.

OSHA matters

On 4 March 2014, BP and the US Occupational Safety and Health Administration (OSHA) reached agreement in relation to the remaining 30 citations issued by OSHA to the Texas City refinery in 2009 related to the Process Safety Management (PSM) standard. This followed an earlier settlement of approximately 400 Texas City citations. The agreement links the outcome of these citations to the ultimate outcome of certain specified Toledo citations which address similar issues (see below). If the 31 July 2013 decision of the Administrative Law Judge in relation to the similar Toledo issues is ultimately upheld when a final decision is entered, 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 North America Inc. (BP Products) and BP- Husky Refining LLC (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 outcome of a pre-trial settlement of a number of the citations and a trial of the remainder was a reduction in the total penalty in respect of the citations from the original amount of approximately $3 million to $80,000. The OSH Review Commission

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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 later this year 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. On 7 December 2015, the complaint was dismissed with prejudice. On 5 January 2016, plaintiffs filed a notice of appeal of that decision to the Ninth Circuit Court of Appeals.

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. On 18 December 2015, the judge denied plaintiffs motion for reconsideration. On 8 January 2016, plaintiffs filed a notice of appeal.

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 were also 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. On 7 December 2015, the European Commission confirmed that it has dropped BP from its investigation.

In addition, 15 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. On 9 April 2015, the BP defendants filed a demurrer, motion to strike and motion to dismiss (forum non conveniens) to the relator s claims that were not adopted in the Attorney General s complaint, which was denied on 10 June 2015. BP filed additional demurrers to the Attorney General s and the relator s complaints, which were granted in part and denied in part on 14 August 2015. On 22 September 2015, BP filed its answer and affirmative defenses. Trial is scheduled to commence on 10 July 2017.

Scharfstein v. BP West Coast Products, LLC

A purported class action lawsuit was filed against BP West Coast Products, LLC in Oregon State Court under the Oregon Unlawful Trade Practices Act on behalf of customers who used a debit card at ARCO gasoline stations in Oregon during the period 1 January 2011 to 30 August 2013, alleging that ARCO s Oregon sites failed to provide sufficient notice of the 35 cents per transaction debit card fee. After a jury trial and subsequent hearing, in 2014 the jury rendered a verdict against BP and determined that statutory damages of $200 per class member should be awarded. On 25 August 2015, the court determined the size of the class to be slightly in excess of two million members. BP intends to appeal. No provision has been made for damages arising out of this class action.

See Financial statements Note 32 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.

The US and the EU sanctions against Iran that were in place in 2015 included: 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 or its affiliates have knowingly engaged in certain, principally Iran-related, activities.

The US and the EU implemented temporary, limited and reversible relief of certain sanctions related to Iran pursuant to a Joint Plan of Action (JPOA) entered by Iran, China, France, Germany, Russia, the UK and the US with effect from 20 January 2014 and in July 2015, these countries agreed the Joint Comprehensive Plan of Action (JCPOA). Following the JCPOA, BP representatives visited Iran, met Iranian government officials and met other Iranian nationals. Such meetings were introductory in nature with a view to considering possible future business opportunities.

Following confirmation by the International Atomic Energy Agency on 16 January 2016 (Implementation Day) that Iran had fully implemented the JCPOA measures necessary for sanctions relief, the European Union and the United States lifted certain nuclear related sanctions, with the EU lifting nuclear related primary sanctions and the United States suspending nuclear related secondary sanctions. BP will consider future business opportunities in relation to Iran and engage in discussions with Iranian government officials and other Iranian nationals, insofar as this is in compliance with applicable sanctions.

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 managed IOC UK s interest in the Rhum field, thereby permitting Rhum operations to recommence in accordance with applicable EU regulations and in compliance with a licence from OFAC. Operations at the Rhum gas field recommenced in mid-October 2014. Following Implementation Day, the Temporary Management Scheme will cease and BP has applied for an amended OFAC licence. In the meantime, operations have continued at Rhum.

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 US sanctions, and fall within the exception for certain natural gas projects under Section 603 of ITRA.

BP has no current operating activities in Iran. BP 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 had ceased in January 2014 but resumed in 2015.

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.

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 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. On 15 January 2016 BP announced that it had signed definitive agreements with Rosneft to dissolve 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 2015, BP recorded gross revenues of $104.5 million related to its interests in Rhum. BP had a net profit of $88.7 million for the year ended 31 December 2015, including an impairment reversal of $67.6 million in the fourth quarter of 2015.

BP currently intends to continue to hold its ownership stake in the Rhum joint arrangement and act as operator.

Material contracts

On 13 March 2014, BP, BP Exploration & Production Inc., 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.

BP Exploration & Production Inc., BP Corporation North America Inc., BP p.l.c., the United States and the states of Alabama, Florida, Louisiana, Mississippi and Texas (the Gulf states) entered into a proposed Consent Decree to fully and finally resolve any and all natural resource damages (NRD) claims of the United States, the Gulf states, and their respective natural resource trustees and all Clean Water Act (CWA) penalty claims, and certain other claims of the United States and the Gulf states. The United States lodged the proposed Consent Decree with the district court in MDL 2179 on 5 October 2015.

Concurrently, BP entered into a definitive Settlement Agreement with the Gulf states (Settlement Agreement) with respect to State claims for economic, property and other losses.

The proposed Consent Decree and the Settlement Agreement are conditional upon each other and neither will become effective unless there is final court approval of the Consent Decree. BP has filed the proposed Consent Decree and the Settlement Agreement as exhibits to its *Annual Report on Form 20-F 2015* filed with the SEC. For further details of the proposed Consent Decree and the Settlement Agreement, see Legal proceedings on page 238.

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 2015 and the group percentage of ordinary share capital see Financial statements Note 36. For information on significant joint ventures and associates* of the group see Financial statements Notes 15 and 16.

Related-party transactions

Transactions between the group and its significant joint ventures and associates are summarized in Financial statements Note 15 and Note 16. 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 2015 to 16 February 2016.

Corporate governance practices

In the US, BP ADSs are listed on the New York Stock Exchange (NYSE). The significant differences between BP s corporate governance practices as a UK company and those required by NYSE listing standards for US companies are listed as follows:

Independence

BP has adopted a robust set of board governance principles, which reflect the UK Corporate Governance Code and its principles-based approach to corporate governance. As such, the way in which BP makes determinations of directors independence differs from the NYSE rules.

BP s board governance principles require that all non-executive directors be determined by the board to be independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement . The BP board has determined that, in its judgement, all of the non-executive directors are independent. In doing so, however, the board did not explicitly take into consideration the independence requirements outlined in the NYSE s listing standards.

Committees

BP has a number of board committees that are broadly comparable in purpose and composition to those required by NYSE rules for domestic US companies. For instance, BP has a chairman s (rather than executive) committee, nomination (rather than nominating/corporate governance) committee and remuneration (rather than compensation) committee. BP also has an audit committee, which NYSE rules require for both US companies and foreign private issuers. These committees are composed solely of non-executive directors whom the board has determined to be independent, in the manner described above.

The BP board governance principles prescribe the composition, main tasks and requirements of each of the committees (see the board committee reports on pages 68-75). 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 68). 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 members of the board, 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 2015 fiscal year, management conducted an assessment of the effectiveness of internal control over financial reporting in accordance with the UK Financial Reporting Council s Guidance on Risk Management, Internal Control and Related Financial and Business Reporting. Based on this assessment, management has determined that BP s internal control over financial reporting as of 31 December 2015 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 2015 has been audited by Ernst & Young, an independent registered public accounting firm, as stated in their report appearing on page 101 of *BP Annual Report and Form 20-F 2015*.

Changes in internal control over financial reporting

There were no changes in the group s internal control 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 35 and Audit committee report on page 68 for details of fees for services provided by auditors.)

Directors report information

This section of *BP Annual Report and Form 20-F 2015* 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 2015. During the year, a review of the terms and scope of the policy was undertaken. The policy was renewed during 2015 and continued into 2016. 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. Certain subsidiaries are trustees of the group s pension schemes. Each director of these subsidiaries* 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 51-52, Liquidity and capital resources on page 219 and Financial statements Notes 28 and 29.

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 28.

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 business model and strategy on pages 12-17.

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 pages 49-50.

Employee share schemes

Certain shares held as a result of participation in some employee share plans carry voting rights. Voting rights in respect of such shares are exercisable via a nominee. Dividend waivers are in place in respect of unallocated shares held in employee share plan trusts.

Change of control provisions

On 5 October 2015, the United States lodged with the district court in MDL 2179 a proposed Consent Decree between the United States, the Gulf states, BP Exploration & Production Inc., BP Corporation North America Inc. and BP p.l.c., to fully and finally resolve any and all natural resource damages claims of the United States, the Gulf states and their respective natural resource trustees and all Clean Water Act penalty claims, and certain other claims of the United States and the Gulf states. Concurrently, BP entered into a definitive Settlement Agreement with the five Gulf states (Settlement Agreement) with respect to state claims for economic, property and other losses. The proposed Consent Decree

* Defined on page 256.

and the Settlement Agreement are conditional upon each other and neither will become effective unless there is final court approval of the Consent Decree. The United States is expected to file a motion with the court to enter the Consent Decree as a final settlement around the end of March, which the court will then consider. The federal government and the Gulf states may jointly elect to accelerate the payments under the Consent Decree in the event of a change of control or insolvency of BP p.l.c., and the Gulf states individually have similar acceleration rights under the Settlement Agreement. For further details of the proposed Consent Decree and the Settlement Agreement, see Legal proceedings on page 238.

Greenhouse gas emissions

The disclosures in relation to greenhouse gas emissions are included in Corporate responsibility Environment and society on page 46.

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	128
(2) (11)	Not applicable
(12), (13) Dividend waivers	245
(14)	Not applicable

Cautionary statement

In order to utilize the safe harbor provisions of the United States Private Securities Litigation Reform Act of 1995 (the PSLRA), BP is providing the following cautionary statement. This document contains certain forecasts, projections and forward-looking statements that is, statements related to future, not past events with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , aims , should , may , objective , is likely to , intends , believes , anticipates , plans , we see expressions. In particular, among other statements, (i) certain statements in the Chairman s letter (pages 6-7), the Group chief executive s letter (pages 8-9), the Strategic report (pages 1-54), Additional disclosures (pages 215-246) and Shareholder information (pages 247-258), including but not limited to statements under the headings Our market outlook , Our business model and strategy , Beyond 2035 , Our distinctive capabilities and Lower oil and gas prices including but not limited to statements regarding plans and prospects relating to future value creation, long-term growth, capital discipline and growth in sustainable free cash flow and shareholder distributions; future dividend and optional scrip dividend payments; expectations regarding the effective tax rate in 2016; future working capital and cash management and the net debt ratio; our intention to maintain a strong cash position; expected payments under contractual and commercial commitments and purchase obligations; our aim to rebalance our sources and uses of cash by 2017; expectations regarding our ability to respond to the current low oil price environment; plans and expectations regarding capital expenditure, reduction in our cost base and cash costs, divestments and gearing in 2016 and beyond; plans to reduce our workforce and third-party spend in the near term; expectations regarding underlying production and capital investment in 2016; plans to invest in a balanced range of resources and geographies; plans and expectations regarding the settlement of legal exposures relating to the Deepwater Horizon incident and the court approval thereof; plans regarding production and value creation from new projects including at Shah Deniz 2 in

Azerbaijan and Khazzan in Oman; expectations regarding the future level of oil and gas prices and industry product supply, demand and pricing in the near and long term, demographic changes and their effect on demand for energy and our outlook and projections of future energy trends, including the role of oil, gas and renewables therein; plans to strengthen our portfolio of high-return and longer-life assets and improve operations; plans to form key partnerships and relationships with governments, customers, partners, communities, suppliers and other institutions; expectations regarding advances in technology including from research at the BP International Centre for Advanced Materials; plans to undertake joint exploration with Rosneft including in East Siberia, the West Siberian and Yenisey-Khatanga basins and the Volga-Urals region of Russia; expectations regarding future managed base decline and the current and future prospects of our discoveries, resources, reserves and positions; plans and expectations regarding the timing and composition of future projects, including with regard to the Atoll discovery in Egypt; expectations regarding the 2016 environment for refining and refinery turnarounds; plans to dissolve our German joint operation with Rosneft, to dispose of our Amsterdam oil terminal and to enter into joint ventures on certain midstream assets in North American and Australia; plans to roll out BP fuels with *ACTIVE* technology in Spain and additional markets in 2016; plans and expectations with regard to the strategic aims of Air BP and our lubricants business; expectations regarding improvements in operating performance and efficiency in the petrochemicals business; expectations regarding future safety performance

and plans to enhance safety, cybersecurity, compliance and risk management; the future strategy for and planned investments in renewable energy including investment in biobutanol; plans and expectations regarding the annual charges of Other business and corporate for 2016, the introduction of 28 deep-sea oil tankers and six LNG tankers into the BP-operated fleet between 2016 and 2019 and improvements in production, revenue and life of fields from investment in equipment and maintenance; expectations regarding the actions of contractors and partners and their terms of service; expectations regarding future environmental regulations and policy, their impact on our business and plans to reduce our environmental impact; our plans to work collaboratively with government regulators in planning for oil spill response and to implement its human rights policy; our planned disclosures regarding payments to governments in compliance with the EU Accounting Directive; plans to reduce activity and simplify processes in response to the current low oil price environment; our aim to develop the capabilities of its workforce with a focus on maintaining safe and reliable operations; our aim to maintain a diverse workforce, create an inclusive environment and ensure equal opportunity, including for women to represent 25% of group leaders by 2020; policies and goals related to risk management; expectations regarding future Upstream operations, including agreements or contracts with or relating to the Clair field, the Gulf of Mexico, Canada and the Canadian Beaufort Sea, Nova Scotia and Newfoundland; our joint ownership interests in exploration concessions and plans to drill therein; plans to transfer operatorship of certain fields; plans related to the Loyal field, the Culzean field, the North Sea and Alaska; plans and expectations regarding our equity interests and partnerships in Angola, Algeria, Libya and Egypt; plans and expectations regarding Western Indonesia, China, Azerbaijan, Oman, Abu Dhabi, India, Iraq and Russia; plans and expectations regarding our activities in Australia and Eastern Indonesia; projections regarding oil and gas reserves, including recovery and turnover time thereof; plans regarding compliance with environmental regulation; our plans and expectations regarding settlement of claims related to the Deepwater Horizon incident and related legal proceedings; 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 our intentions in respect thereof; and (ii) certain statements in Corporate governance (pages 55-75) and the Directors remuneration report (pages 76-92) 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 review of our governance policies in 2016, the timing of future audit contract tendering and areas of focus for the audit committee; and goals and areas of focus of board committees, including the Safety, ethics and environment assurance committee, the Geopolitical committee and the Chairman s and nomination committees; 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 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; cyberattacks or sabotage; and other factors discussed elsewhere in this report including under Risk factors (pages 53-54). 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 our 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 our 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				
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
2015	**484.15**	**322.90**	**43.60**	**29.38**
Year ended 31 December				
2014: First quarter (January-March)	510.00	462.64	51.02	45.83
Second quarter (April-June)	526.80	467.10	53.48	47.14
Third quarter (July-September)	525.80	440.72	53.48	43.80
Fourth quarter (October-December)	455.45	364.40	44.14	34.88
2015: First quarter (January-March)	**457.10**	**382.15**	**41.93**	**35.67**

Second quarter (April-June)	**484.15**	**420.15**	**43.60**	**39.50**
Third quarter (July-September)	**437.40**	**322.90**	**41.29**	**29.38**
Fourth quarter (October-December)	**403.25**	**329.30**	**37.23**	**30.13**
2016: First quarter (to 16 February)	**376.10**	**310.25**	**32.37**	**27.64**
Month of				
September 2015	**355.85**	**322.90**	**32.41**	**29.38**
October 2015	**391.70**	**342.25**	**35.96**	**30.96**
November 2015	**403.25**	**364.50**	**37.23**	**33.38**
December 2015	**384.55**	**329.30**	**34.77**	**30.13**
January 2016	**376.10**	**323.10**	**32.37**	**28.46**
February 2016 (to 16 February)	**366.95**	**310.25**	**31.70**	**27.64**

[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 16 February 2016, 893,653,858.5 ADSs (equivalent to approximately 5,361,923,151 ordinary shares or some 29.01% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 92,375 ADS holders. Of these, about 91,266 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 999,817 underlying holders.

On 16 February 2016, there were approximately 262,938 ordinary shareholders. Of these shareholders, around 1,577 had registered addresses in the US and held a total of some 4,108,986 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 9.

A Scrip Dividend Programme (Scrip Programme) was approved by shareholders in 2010 and was renewed for a further three years at the 2015 AGM. 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 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 53 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 219.

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
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
2015	**UK pence**	**40.00**	**39.18**	**39.29**	**39.81**	**158.28**
	US cents	**60**	**60**	**60**	**60**	**240**

[a] Dividends announced and paid by the company on ordinary and preference shares are provided in Financial statements Note 9.

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.

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, inter alia 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 until 5 April 2016, is 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.

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. US ADS holders should consult their own tax advisor regarding the US tax treatment of the dividend fee in respect of dividends. 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.

As noted above in UK taxation, a US holder will not be subject to UK withholding tax. Accordingly, the receipt of a dividend will not entitle the US holder to a foreign tax credit.

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.

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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) resident for tax purposes in the United Kingdom at the date of disposal, (ii) if he has left the UK for a period not exceeding five complete tax years between the year of departure from and the year of return to the UK and acquired the shares before leaving the UK and was resident in the UK in the previous four out of seven tax years before the year of departure, (iii) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK or (iv) 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 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 2015

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	55,102	20.93	0.01
201-1,000	91,461	34.73	0.27
1,001-10,000	104,537	39.70	1.75
10,001-100,000	10,801	4.10	1.19
100,001-1,000,000	761	0.29	1.55
Over 1,000,000[a]	650	0.25	95.23
Totals	263,312	100.00	100.00

[a] Includes JPMorgan Chase Bank, N.A. holding 29.04% 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 2015[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	54,200	58.44	0.34
201-1,000	24,782	26.73	1.33
1,001-10,000	13,097	14.12	3.84
10,001-100,000	662	0.71	1.23
100,001-1,000,000	9	0.00	0.16
Over 1,000,000[b]	1	0.00	93.10
Totals	92,751	100.00	100.00

[a] One ADS represents six 25 cent ordinary shares.

[b] One holder of ADSs represents 991,246 underlying shareholders, as at 11 January 2016.

As at 31 December 2015, there were also 1,436 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 2015 BlackRock, Inc held 6.42% and Legal & General Group plc held 3.23% of the voting rights of the issued share capital of the company. As at

16 February 2016 BlackRock, Inc. held 6.86% and Legal & General Group plc held 3.21% 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 16 February 2016:

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	5,361,923,151	29.01
BlackRock, Inc.	1,269,247,291	6.86

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 16 February 2016:

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
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
Bank Julius Baer	294,000	5.37
Smith & Williamson Investment Management Ltd.	279,500	5.11

In accordance with DTR 5.8.12, 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.

UBS Investment Bank notified the company that its indirect interest in ordinary shares increased above 3% on 7 May 2015 and that it decreased below the notifiable threshold on 11 May 2015.

The Capital Group of Companies, Inc. notified the company that its indirect interest in ordinary shares decreased below the notifiable threshold on 21 July 2015.

UBS Investment Bank notified the company that its indirect interest in ordinary shares increased above 3% on 4 November 2015 and that it decreased below the notifiable threshold on 9 November 2015.

BlackRock, Inc. notified the company that its indirect interest in ordinary shares remained above the previously disclosed threshold of 5%, on 26 November 2015, that it decreased below 5% on 4 February 2016 and that it increased above 5% on 15 February 2016.

As at 16 February 2016, 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 2016 AGM will be held on Thursday 14 April 2016 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 2016*.

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 254.

The company s Articles of Association may be amended by a special resolution at a general meeting of the shareholders. At the annual general meeting (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. At the AGM held on 16 April 2015 shareholders voted to adopt new Articles of Association to reflect developments in practice and to provide clarification and additional flexibility.

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, notice of which is first given after their appointment 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. In addition, the company may by special resolution remove a director before the expiration of his/her period of office and, subject to the Articles of Association, may by ordinary resolution appoint another person to be a director instead. 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.
- Any proposal concerning the giving to the director of any other indemnity which is on substantially the same terms as indemnities given or to be given to all of the other directors or to the funding by the company of his expenditure on defending proceedings or the doing by the company of anything to enable the director to avoid incurring such expenditure where all other directors have been given or are to be given substantially the same arrangements.
- Any proposal concerning an arrangement for the benefit of the employees and directors or former employees and former directors of the company or any of its subsidiary undertakings, including but without being limited to a retirement benefits scheme and an employees share scheme, which does not accord to any director any privilege or advantage not generally accorded to the employees or former employees to whom the arrangement relates.

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 two times 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. If the company exercises its right to forfeit shares and sells shares belonging to an untraced shareholder then any dividends or other monies unclaimed in respect of those shares will be forfeited after a period of two years.

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 was renewed at the company s AGM held on 16 April 2015 for a further three years. 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.

For the purposes of determining which persons are entitled to attend or vote at a shareholders meeting and how many votes such persons may cast, the company may specify in the notice of the meeting a time, not more than 48 hours before the time of the meeting, by which a person who holds shares in registered form must be entered on the company s register of members in order to have the right to attend or vote at the meeting or to appoint a proxy to do so.

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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, provided that a duly completed proxy form is received not less than 48 hours (or such shorter time as the directors may determine) before the time of the meeting or adjourned meeting or, where the poll is to be taken after the date of the meeting, not less than 24 hours (or such shorter time as the directors may determine) before the time of the poll.

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.

Corporations who are members of the company may appoint one or more persons to act as their representative or representatives at any shareholders meeting provided that the company may require a corporate representative to produce a certified copy of the resolution appointing them before they are permitted to exercise their powers.

Matters are transacted at shareholders meetings by the proposing and passing of resolutions, of which there are two types: ordinary or special.

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. Any AGM requires 21 clear days notice. The notice period for any other general meeting is 14 clear days subject to the company obtaining annual shareholder approval, failing which, a 21 clear 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 252 under the heading Voting rights.

Under the Act, the AGM of shareholders must be held once every year, within each six month period beginning with the day following the

company s accounting reference date. All general meetings shall be held at a time and place (in England) determined by the directors. If any shareholders meeting is adjourned for lack of quorum, notice of the time and place of the adjourned 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 and any new shares in the company issued 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 2015 are set out in Financial statements Note 30. At the AGM on 16 April 2015, authorization was given to the directors to allot shares up to an aggregate nominal amount equal to $3,040 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 $228 million, without having to offer such shares to existing shareholders. These authorities were given for the period until the next AGM in 2016 or 16 July 2016, whichever is the earlier. These authorities are renewed annually at the AGM.

Purchases of equity securities by the issuer and affiliated purchasers

At the AGM on 16 April 2015, authorization was given to the company to repurchase up to 1.8 billion ordinary shares for the period until the next AGM in 2016 or 16 July 2016, being the latest dates by which an AGM must be held for that year. This authorization is renewed annually at the AGM. No ordinary shares were repurchased during 2015. The following table provides 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.

	Number of shares purchased by ESOPs or for certain employee share-based plans[a]	Average price paid per share $
2015		
January 5 January 30	**36,600,000**	**6.19**
February 2 to February 5	**6,960,000**	**6.50**
September 21	**1,132,000**	**5.22**
October 29	**2,800,000**	**5.99**
November 3 November 4	**2,700,000**	**5.94**
December 15	**950,000**	**5.16**
2016		
January 1 January 31	**Nil**	
February 1 to February 16	**Nil**	

[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.

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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.
Dividend fees	ADS holders who receive a cash dividend are charged a fee which BP uses to offset the costs	US$0.005 per BP ADS per quarter per cash distribution.

associated with administering the ADS programme.

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 2015. The Depositary reimbursed to the company, or paid amounts on the company s behalf to third parties, or waived its fees and expenses, of $11,858,206.46 for the year ended 31 December 2015.

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 2015. 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 2015 $
Service fees and out of pocket expenses waived[a]	37,650
Other third-party mailing costs reimbursed[b]	54,014.67
Dividend fees[c]	11,766,541.79
Total	11,858,206.46

[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] Payment of fees to Precision IR for investor support.

[c] Dividend fees are charged to ADS holders who receive a cash distribution, which BP uses to offset the costs associated with administering the ADS programme.

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 certain 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 2015 and *BP Strategic Report 2015* 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 in this report (see Corporate governance practices (Form 20-F Item 16G) on page 244) 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 4.7	Director s Service Contract for Dr B Gilvary****
Exhibit 4.10	The BP Share Award Plan 2015
Exhibit 7	Computation of Ratio of Earnings to Fixed Charges (Unaudited)
Exhibit 8	Subsidiaries (included as Note 36 to the Financial Statements)

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
Exhibit 15.3	Administrative Agreement dated as of 13 March 2014 among the US Environmental Protection Agency, BP p.l.c., and other BP subsidiaries***
Exhibit 15.4	Proposed Consent Decree
Exhibit 15.5	Gulf states Settlement Agreement

* 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 2014.

**** 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.

GHG

Greenhouse gas.

GWh

Gigawatt hour.

HSSE

Health, safety, security and environment.

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.

MW

Megawatt.

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 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.

Brent

A trading classification for North Sea crude oil that serves as a major benchmark price for purchases of oil worldwide.

Cash costs

Non-GAAP measure. Cash costs are a subset of production and manufacturing expenses plus distribution and administration expenses and excludes costs that are classified as non-operating items. They represent the substantial majority of the remaining expenses in these line items but exclude certain costs that are variable, primarily with volumes (such as freight costs). Management believes that the presentation of cash costs is a performance measure that provides investors with useful information regarding the company s financial condition because it considers these expenses to be the principal operating and overhead expenses that are most directly under their control although they also include certain foreign exchange and commodity price effects.

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 34. 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 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 margin, are generally 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 announced in respect of the year as a percentage of the year-end share price on the respective exchange. The ordinary shareholders annual dividend yield includes an estimate of the sterling amount expected to be paid in respect of the dividend for the fourth quarter 2015 which was announced on 2 February 2016 in US dollars.

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

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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 group cash flow statement.

Gearing

See Net debt and net debt ratio definition.

Henry Hub

A distribution hub on the natural gas pipeline system in Erath, Louisiana, that lends its name to the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange and the over the counter swaps traded on Intercontinental Exchange.

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 the Upstream segment, it also includes bitumen.

LNG train

An LNG train is a processing facility used to liquefy and purify natural gas in the formation of LNG.

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 cash margin

Net cash margin is defined by Solomon Associates as the net margin achieved after subtracting cash operating expenses and adding any refinery revenue from other sources. Net cash margin is expressed in US dollars per barrel of net refinery input.

Net debt and net debt ratio (gearing)

Non-GAAP measures. 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 currency exchange and interest rate risks relating to finance debt, for which hedge accounting is applied, less cash and cash equivalents. The net debt ratio is defined as the ratio of net debt to the total of net debt plus total equity. All components of equity are included in the denominator of the calculation. 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 . See Financial statements Note 26 for information on gross debt, which is the nearest equivalent measure to net debt on an IFRS basis.

Net income per barrel

Non-GAAP measure. Net income per barrel is calculated by taking underlying replacement cost profit before interest and tax for the Downstream segment, deducting tax at an assumed 30% effective tax rate on underlying replacement cost profit and then dividing this notional post tax underlying replacement cost profit by the Downstream segment s total refining capacity.

Net investment (organic)

Net investment (organic) is organic capital expenditure less the value of divestments announced in the year.

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-joint venture basis, which includes 100% of the capacity of equity-accounted entities where BP has partial ownership.

Non-operating items

Charges and credits are included in the financial statements 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. Non-operating items within equity-accounted earnings are reported net of incremental income tax reported by the equity-accounted entity. An analysis of non-operating items by segment and type is shown on page 217.

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 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 5.

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Plant reliability

Plant reliability is calculated taking 100% less the ratio of total unplanned plant deferrals divided by installed production capacity. Unplanned plant deferrals are associated with the topside plant and where applicable the subsea equipment (excluding wells and reservoir). Unplanned plant deferrals include breakdowns and weather.

Pre-tax returns

Non-GAAP measure. Pre-tax returns is the ratio of underlying replacement cost profit before interest and tax to the average operating capital employed for the period.

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.

Realizations

Realizations are the result of dividing revenue generated from hydrocarbon sales, excluding revenue generated from purchases made for resale and royalty volumes, by revenue generating hydrocarbon production volumes. Revenue generating hydrocarbon production reflects the BP share of production as adjusted for any production which does not generate revenue. Adjustments may include losses due to shrinkage, amounts consumed during processing, and contractual or regulatory host committed volumes such as royalties.

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 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 5.

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 oil and gas

Natural oil and gas reservoirs locked in hard sandstone rocks with low permeability, making the underground formation extremely tight.

UK National Balancing Point

A virtual trading location for sale, purchase and exchange of UK natural gas. It is the pricing and delivery point for the Intercontinental Exchange natural gas futures contract.

Unconventionals

Resources found in geographic accumulations over a large area, that usually present additional challenges to development such as low permeability or high viscosity. Examples include shale gas and oil, coalbed methane, gas hydrates and natural bitumen deposits. These typically require specialized extraction technology such as hydraulic fracturing or steam injection.

Underlying production

Production 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 217 and 218 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.

Trade marks

Trade marks of the BP group appear throughout this report. They include:

ACTIVE

Aral

ARCO

BP

Bright Water

Castrol

Independent Simultaneous Source

Nexcel

Field of the Future

Wild Bean Cafe

Apple Pay is a registered trade mark of Apple Inc.

M&S Simply Food is a registered trade mark of Marks & Spencer plc.

The Directors report on pages 55-75, 169-195 and 215-258 was approved by the board and signed on its behalf by David J Jackson, company secretary on 4 March 2016.

BP p.l.c.

Registered in England and Wales No. 102498

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

4 March 2016

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Cross reference to Form 20-F

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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 2015

Details of our financial and operating performance in print and online. Published in March. *bp.com/annualreport*

Strategic Report 2015

A summary of our financial and operating performance in print and online. Published in March. *bp.com/annualreport*

BP Energy Outlook 2016 edition

Projections for world energy markets, considering the global economy, population, policy and technology. Published in February. *bp.com/energyoutlook*

Sustainability Report 2015

Details of our sustainability performance with additional information online. Published in March. *bp.com/sustainability*

Financial and Operating Information 2011-2015

Five-year financial and operating data in PDF and Excel format. Published in April. *bp.com/financialandoperating*

Statistical Review of World Energy 2016

An objective review of key global energy trends. Published in June. *bp.com/statisticalreview*

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